Oilfield Review

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Naturally Fractured Reservoirs
Advancing Earthquake Research
Heavy Oil
National Data Centers
Monitoring Viscous-Oil Production

The world holds more than six trillion barrels of viscous oil, mostly in high-porosity sandstones. In 40 years, at current conventional-oil depletion rates, all oil companies will be heavy-oil companies. This trend has led to the recent emergence of many new production methods for viscous oil. Often, these technologies can be used at the same time or carefully sequenced to improve economic benefits and recovery factors. However, these new processes are so complex that we must monitor them to “see” what is happening underground.

New production methods in commercial use for viscous oils include cold production (CP) flow to horizontal wells, vertical wells exploiting deliberate sand influx (cold heavy-oil production with sand, or CHOPS), steam-assisted gravity drainage (SAGD) and cyclic steam stimulation using horizontal wells (HCS). Processes being field-tested include pressure-pulse stimulation, combustion using horizontal wells, and solvent or vapor-assisted gravity drainage. The article “Highlighting Heavy Oil,” page 34, describes current technologies.

Because unconsolidated sands are weak, CHOPS causes large changes—actually enhancements—in reservoir properties, as do high-temperature and high-pressure processes. Withdrawing large amounts of sand from the reservoir generates high-permeability zones; use of steam leads to massive thermally induced shearing and dilation of weak sands; and injection above fracture pressure breaches thin shale beds and other barriers. Understanding and exploiting these reservoir enhancements require high-quality monitoring data.

Enhanced zones are more porous, permeable and compressible, and this helps process efficiency. Steam injection is much more effective if flow barriers have been breached or sheared, and high compressibilities can lead to recompaction drive, which is important for cyclic thermal processes. These enhancement effects will undoubtedly benefit emerging technologies such as combustion and pressure pulsing. Integrated monitoring of changes in seismic and electrical attributes, density and formation deformation will allow us to quantify these enhancements.

Mapping changes in properties over time allows us to track temperature and pressure fronts, map enhancement zones caused by sand production, and better understand the effects of formation shear, dilation and other phenomena. However, focusing only on conventional monitor wells and time-lapse seismic methods is far too limited. If two or more monitoring methods are used, they complement each other, reducing uncertainty and risk in decision making. Even complex mathematical exercises such as data inversion and modeling of coupled reservoir processes are improved if several complementary datasets are available.

Here are some additional monitoring possibilities:

- Installation of a microseismic monitoring array to track temperature and pressure fronts. Dispersed microseismic events can be analyzed tomographically to link seismic-attribute changes to changes in stresses and pressures, as well as to volumetric and shear distortions.
- Measuring electrical attributes allows analysis of saturation and temperature changes. Installation of a permanent 3D electrode array will permit regular electrical-impedance surveys and frequency-controlled probing.
- A deformation-measurement system using satellite technology (InSAR) with surface and downhole measurements permits analysis of reservoir shear distortions and volume changes.
- Combined with deformation data, gravimetric methods can quantify the distribution of density changes such as those caused by replacing viscous oil with a vapor phase.
- Multiple-sensor monitor wells can be used, perhaps with fiberglass joints to permit installation of electrodes as well as pressure and temperature sensors, accelerometers and deformation devices such as extensometers or magnetic rings for wireline logging.

Production monitoring may also benefit from technical developments such as sensors installed behind well casings, high-temperature pressure sensors and accelerometers, and improved mathematical-inversion methods.

Since most viscous oil is found within 1,000 m [3,280 ft] of the surface, monitoring arrays can be installed relatively inexpensively and provide excellent resolution and high precision. Monitoring will help clarify the physics and mechanics of complex new production technologies, help control them and help perfect the mathematical modeling methods that we use to make predictions. Monitoring provides us with the “eyes” we need to see where we are going, and that’s far better than driving blind.

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The Nature of Naturally Fractured Reservoirs

Natural fractures can help transform rock with low matrix permeability into a productive reservoir, but can also complicate hydrocarbon recovery in high-permeability reservoirs. This article discusses naturally fractured reservoirs and explains how the oil and gas industry manages challenges in fracture detection, characterization and modeling, and in reservoir simulation.

Oilfield Technologies for Earthquake Science

Geoscientists in California, USA, are constructing an underground observatory in the San Andreas Fault to closely monitor earthquakes in the “near field” of seismic-wave propagation. Oilfield technology plays a significant role in construction and instrumentation of this observatory.
34  **Highlighting Heavy Oil**

With the decline in production of conventional oils and the need to replenish reserves, oil companies are increasingly interested in heavy oil. This article reviews fluid properties of heavy oil and potential production scenarios, from mining to in-situ combustion. Case studies demonstrate techniques for characterizing heavy-oil reservoirs, determining the best recovery method, constructing and completing wells and monitoring production.

54  **The Evolving Dimensions of National Data Centers**

In today's increasingly competitive world, resource holders are using their E&P assets to attract and facilitate investment. National data centers help countries realize the maximum value of existing natural resources and offer expanded services that promote investment in petroleum and other industries.

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The Nature of Naturally Fractured Reservoirs

Naturally fractured reservoirs present a production paradox. They include reservoirs with low hydrocarbon recovery: these reservoirs initially may appear highly productive, only to decline rapidly. They are also notorious for early gas or water breakthrough. On the other hand, they represent some of the largest, most productive reservoirs on Earth. The paradoxical nature of this class of reservoirs is the impetus behind the industry’s efforts to learn more about them and model them with a reasonable amount of certainty.

Nearly all hydrocarbon reservoirs are affected in some way by natural fractures, yet the effects of fractures are often poorly understood and largely underestimated. In carbonate reservoirs, natural fractures help create secondary porosity and promote communication between reservoir compartments. However, these high-permeability conduits sometimes short-circuit fluid flow within a reservoir, leading to premature water or gas production and making secondary-recovery efforts ineffective. Natural fractures also occur in siliciclastic reservoirs of all types, complicating seemingly straightforward matrix-dominated production behavior. In addition, natural fractures are the main producibility factor in a wide range of less conventional reservoirs, including coalbed-methane (CBM), shale-gas, basement-rock and volcanic-rock reservoirs. Although natural fractures play a lesser role in high-porosity, high-permeability reservoirs such as turbidites, they commonly form barriers to flow, frustrating attempts to accurately calculate recoverable reserves and predict production over time.

Ignoring the presence of fractures is not optimal reservoir management; eventually, fractures cannot be ignored because the technical and economic performance of the reservoir degrades. The biggest risk in not characterizing natural fractures early is that such an oversight can severely limit future field-development options. For example, a company that does not take advantage of the opportunities to evaluate natural fractures during the early development stage may waste resources on unnecessary infill drilling. Asset teams may never extract the hydrocarbons originally deemed recoverable because, without understanding the impact of natural fractures on production behavior, they have not adequately prepared the field for secondary recovery.

This article examines the impact of natural fractures on hydrocarbon reservoirs at different stages of reservoir development. The classifications of natural fractures and naturally fractured reservoirs (NFRs) are reviewed, along with factors that affect NFR behavior. We describe methods used over a range of scales to identify and characterize natural fractures and to model the influence of fracture systems on production. Case studies from around the world highlight various approaches.

Natural Fractures in Field Development

The investigation of natural fractures should start during the exploration stage. Relevant surface outcrops of the reservoir section or reservoir analogs can form the basis of a lithological, structural and stratigraphic foundation from which geologists build conceptual models. These models often begin with knowledge of the regional stresses (next page). The stress state is important in NFRs because the stress state...
largely dictates whether fractures are open to conduct reservoir fluids. In addition, the magnitude and direction of horizontal stresses play critical roles in hydraulic fracture design, the primary stimulation method for NFRs.

Multicomponent (3C) seismic surveys acquired early in field development yield important data for determination of azimuthal anisotropy, which is essential to characterize natural fractures and to place wells effectively. For example, knowing the general orientation of fracture systems during well planning dramatically improves the chance that a well will intersect fractures.

New wells present an opportunity to collect appropriate geological, geophysical and mechanical data from many sources, including information from logging tools, borehole seismic surveys, sampling devices and fullbore cores. Other valuable sources of information that can be acquired during the early stages of field development include drillstem tests, initial flow tests, and buildup and drawdown tests. Properly assessing the role of natural fractures can result in early field-development successes and can lay the groundwork for later development stages, including secondary-recovery projects.

Information about natural fractures is also important during the well-construction stage. During overbalanced drilling and cementing operations, open natural fractures can cause lost circulation problems, loss of expensive drilling fluids and the potential loss of wells. A less obvious cost may be associated with the reduced productivity that results when drilling fluids and cement seal fractures that were once open and potentially productive.1 Employing underbalanced drilling techniques and using less damaging

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drilling or cementing fluids are possible ways to reduce lost circulation and its associated damage. However, in many cases, drillers’ options are more limited.

When drilling weakened and depleted NFRs surrounded by low-permeability shales or over pressured zones, drillers must maintain a certain mud weight to support the shale or prevent a blowout from the over pressured zone. Through the years, innovative techniques have been developed to limit the risk, cost and damage caused by lost circulation problems. These include heating the drilling fluid to alter the stress state around the borehole; treating the mud with specialized lost circulation material—such as fibers—when losses start to occur; pretreating the drilling fluid with particulate material; and strategically changing the stresses around the wellbore—for example, by creating fractures.4

In some cases, natural fractures are so large that drastic measures are required. For example, in some carbonate NFRs in central Asia, drilling-fluid losses have reached 80,000 barrels [12,712 m3] in long intervals of highly fractured and porous rock. The keys to addressing serious and recurring loss circulation problems are planning for losses, defining the target and having the required equipment and materials available when problems occur.4 A detailed knowledge of the fracture system is essential to mitigation.

Today, MWD tools can monitor critical drilling parameters in real time, allowing drilling engineers to mitigate lost circulation problems. In addition, LWD technology, such as the geoVISION imaging-while-drilling service and the RAB Resistivity-at-the-Bit tool, help identify natural fractures immediately after drilling past them.2 Incorporating natural-fracture information and rock mechanical properties into cement-job designs reduces the risk of opening up natural fractures or accidentally fracturing the formation, both of which could cause lost circulation.

Once well construction and evaluation are finished, the focus moves to designing a completion and stimulation program to undo the damage caused by drilling and cementing. Some form of stimulation is required for most NFRs with a low-permeability matrix. Pumping reactive fluids—acidizing, using various formulations of hydrochloric acid [HCl] or chelants—into natural fractures is most common in carbonate reservoirs to remove near-wellbore damage, enhance connectivity and improve the conductivity of the system.5 During carbonate-rock stimulation using reactive fluids, zones with the highest permeabilities commonly take most of the treatment fluid, leaving the zones with lower permeabilities untreated. Consequently, diversion, leakoff and reaction-rate control are keys to success when acidizing carbonates.6

Conventional approaches to diversion include particulate- and viscosity-based-diversion methods. Particulate diversion uses solids to bridge and restrict flow to highly permeable or fractured zones. For example, rock salt or benzoic acid flakes are pumped to divert in the formation at the loss zone, and ball sealers are used to mechanically divert from inside tubulars at the perforations. Viscosity-based diversion uses foams, and acids or fluids gelled with viscoelastic surfactants or polymers to divert treatment and provide fluid-loss control within the formation. However, polymers have damaged reservoirs, prompting service companies to develop new surfactant-base fluids. For example, the VDA Viscoelastic Diverting Acid system has been used to successfully stimulate fractured carbonate reservoirs all over the world, including Kuwait, Saudi Arabia, Mexico and Kazakhstan.9 In addition, a new technique that uses both technologies—fibrous particulate and viscosity diversion—has been developed for acidizing NFRs.

Natural fractures in siliciclastic reservoirs are also occasionally acidized, typically using a combination of HCl and hydrofluoric acid [HF]. Alternatively, hydraulic fracture stimulation of NFRs requires that the main fracture path be kept open and conductive with proppant. Controlling the leakoff rate and effective proppant placement, while minimizing damage to the natural-fracture network, are critical to achieve optimal stimulation and production.

Natural fractures can significantly limit the ability to place large volumes of proppant within a hydraulically created fracture. Various techniques are used to limit natural-fracture dilation and the corresponding fluid losses during hydraulic fracturing. These include reducing fracture net pressure by rate-control or low-viscosity fluids, and incorporating properly graded particulates to dynamically bridge dilating fissures, thereby reducing total leakoff volume. Additionally, conductivity damage within the created hydraulic fracture and natural-fracture system can be reduced by lowering the total volume of polymer used—for example, by using low-polymer crosslinked frac gels, increasing breaker-to-polymer ratios through the use of encapsulated breakers, or by replacing the polymeric fracture fluid with nondamaging viscoelastic surfactant fluid systems such as ClearFRAC polymer-free frac fluid.10

The volume occupied by typical fractures—open or mineral-filled—within a vast matrix is usually relatively minuscule, yet the ability of fractures to significantly impact fluid-flow behavior in hydrocarbon reservoirs is enormous. It is not surprising that one of the greatest challenges facing reservoir experts is how to adequately simulate the effects of fractures on reservoir behavior. Understanding these reservoirs requires the acquisition and analysis of vast amounts of data, and usually begins with detailed, foot-by-foot characterization of the fracture and matrix systems. It is the interaction between these two systems that must be understood while reservoir properties change with continued production or injection. As field development continues, other information—for example, well-test data, production data, and passive and time-lapse seismic data—helps validate and improve reservoir models.

The strategy a company uses to achieve field-production and recovery potential is intertwined with, and increasingly directed according to, an ever-improving NFR model and simulation. During the primary-production stage, changes in reservoir pressure, and consequently effective stress, alter the fluid flow within fracture networks.12 Water or gas breakthrough is the most common negative implication of conductive fractures during the primary-production stage. Besides adding water production and disposal costs, producing high-mobility water leaves behind substantial volumes of low-mobility oil. Moreover, premature gas production can drain a reservoir of its energy, damage downhole pumps and complicate surface treatment of produced reservoir fluids.

Secondary-recovery techniques using fluid injection also change field pressure and effective stress dynamics, and therefore change fracture conductivity to fluid flow. At this stage in field development, asset teams should be familiar with the role natural fractures play in large-scale fluid movement. Ideally, production and secondary-recovery strategies—well patterns and spacings, and selection of injection and production zones—should reflect the level of influence that natural fractures have on hydrocarbon sweep as determined by simulation.
that form with tension perpendicular to the characteristics of fracture and fault systems is essential. The complexity of natural-fracture systems is captured in the descriptive, genetic and geometric methods that geoscientists employ to classify natural fractures. Knowing fracture types enhances the simulation of fluid flow through fractures, because various types of fractures conduct fluid differently.

To appreciate common classification schemes, a basic understanding of how natural fractures develop is needed. However, achieving this understanding requires more than extensive field observation of natural fractures; it requires linking those observations with data from controlled laboratory experiments. In the laboratory, fracture types are divided into two groups related to their mode of formation: shear fractures that form with shearing parallel to the created fracture, and tension fractures that form with tension perpendicular to the created fracture.

In the laboratory, shear and tension fractures form in consistent orientation with respect to the three principal stress directions, namely the maximum compressive principal stress, $\sigma_1$, the minimum compressive principal stress, $\sigma_3$, and the intermediate stress, $\sigma_2$. Shear fractures are created under high differential stress and in conjugate pairs, forming an acute angle with $\sigma_1$. Tension fractures, a term sometimes used interchangeably with extension fractures, form perpendicular to $\sigma_2$ and at relatively low differential stresses, when the value of $\sigma_2$ after adjustment for pore pressure—the local effective stress—is likely tensile. In the laboratory, it is common to observe the creation of tension fractures during compression experiments at low confining pressures and in association with shear fracturing.15

Shear and tension fractures described from laboratory experiments have clear counterparts that occur naturally; shear fractures correspond to faults, whereas tension fractures correspond to joints.14 This mechanically based distinction provides a useful way to classify fractures. Most faulting occurs during significant tectonic events when the differential stress is high. Tectonic faults typically occur over a broad range of scales, with displacements that range from millimeters to kilometers. Seismic images generally allow the detection of the larger faults, while borehole data are required to identify and characterize smaller faults. Tectonic faults typically cut unimpeded through stratigraphy and are therefore termed non-stratabound.

Joints, or fractures having no visible displacement, form perpendicular to bedding. Joints can be either stratabound or non-stratabound. Stratabound joints stop at bedding surfaces and often develop a regular spacing and form well-organized connected networks in plan view. Commonly, there is a long and continuous set of joints, termed systematic joints, which are joined by a perpendicular array of cross joints that abut the systematic joints. Non-stratabound joints occur on a wide range of scales and are spatially clumped.17

Classifying Fractures

When developing and modeling fractured reservoirs, the ability to understand and predict the characteristics of fracture and fault systems is essential.13 The complexity of natural-fracture systems is captured in the descriptive, genetic and geometric methods that geoscientists employ to classify natural fractures. Knowing fracture types enhances the simulation of fluid flow through fractures, because various types of fractures conduct fluid differently.


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The origin of joints is often difficult to determine, but it is known from rock mechanics that they occur at low effective $\sigma_3$. Truly tensile stress occurs at shallow depths, so some joints form close to the surface. However, at reservoir depths, joints can probably form only under high fluid pressure, a process similar to hydraulic fracturing during well stimulation.

As joints do not involve displacement that offsets bedding, they cannot be directly observed on seismic images, but can be located and characterized by well-log data and borehole images (above). While it is relatively simple for a geologist to distinguish faults and joints at an outcrop, the distinction is often less clear using subsurface data, as stratigraphic offsets may not be resolvable. Geologists may therefore have to rely on a number of criteria, such as fracture fill, orientation and spatial distribution, to determine whether fractures of a given set are likely to be faults or joints. It may be necessary in such cases to develop a pragmatic classification system based on observed properties of the fractures.

Other types of fractures are created by volume-reduction mechanisms within the rock and not from external forces. These include desiccation cracks, syneresis fractures, thermal contraction fractures and mineral phase-change fractures. Of these, syneresis, or chicken-wire fractures, and mineral phase-change fractures in carbonates have the greatest importance in oil and gas production. Syneresis fractures are formed by a chemical process that causes dewatering and associated volume reduction.

Carbonate rocks are easily dissolved in freshwater or aggressive fluids and the dissolution is often concentrated to form caves or vugs. The resulting porosity is termed karst and is important in many fractured carbonate reservoirs. Maps of karst often show that the porosity is most strongly enhanced along the planes of preexisting fractures and so clarifying the underlying fracture system can often help in understanding karst systems.

Because carbonates dissolve relatively easily under pressure, they have a tendency to form stylolites—uneven surfaces of insoluble residue—that form perpendicular to $\sigma_3$. Stylolites may cause local permeability reduction, or alternatively they may facilitate subsequent dissolution and permeability increase. Tension gashes, or fracturing associated with stylolites, are common (next page, top). While tension gashes may contribute to permeability measured in core, their subsurface impact on reservoir producibility is thought to be minimal.

A genetic classification system examines how fractures relate to the formation and the structure in which they are located. The creation of endogenetic fractures relates to the stresses during sedimentation, for example cleating in coals. Exogenetic fractures are formed after sedimentation and lithification, usually from tectonic stresses caused by folding and faulting. Once natural-fracture systems have been classified in both geologic and engineering terms, the next step is to investigate their impact on the reservoir.

Classifying Fractured Reservoirs

Most, if not all, reservoirs contain fractures. It is the degree to which fractures influence fluid flow through a reservoir that should dictate the level of resources needed to identify, characterize and model fractures. The effects of fractures can change throughout the productive life of the reservoir as pressures and fluid types change during primary- and secondary-recovery stages. Moreover, fractures don’t always conduct fluid; they are often barriers to flow. Fractured reservoirs are classified based on the interaction between the relative porosity and permeability contributions from both the fracture and matrix systems (next page, bottom).

In Type 1 reservoirs, fractures provide both the porosity and permeability elements. Type 2 reservoirs have low porosity and low permeability in the matrix, and fractures provide the essential permeability for productivity. Type 3 reservoirs have high porosity and may produce without fractures, so fractures in these reservoirs provide added permeability. Type M reservoirs have high matrix porosity and permeability, so open fractures can enhance permeability, but natural
fractures often complicate fluid flow in these reservoirs by forming barriers. Fractures add no significant additional porosity and permeability to Type 4 reservoirs, but instead are usually barriers to flow. Another reservoir class, Type G, has been created for unconventional fractured gas reservoirs, such as CBM, and fractured gas-condensate reservoirs. Most Type G reservoirs fall within or near the Type 2 reservoir classification.

Before NFR classification can be done in any meaningful way, both natural-fracture and matrix systems within a reservoir must be understood, along with the complex flow interaction between those systems. Many factors affect fluid flow within a NFR, including present-day stress orientation, natural-fracture directions, whether the fractures are mineral-filled or open, reservoir fluid properties and phases, and the production and injection history of the field. While many of these factors cannot be controlled, some problems can be mitigated. Field-development strategies can therefore be tailored to the natural-fracture systems to optimize production and recovery. The sooner this knowledge is acquired, the more prepared asset teams will be to make important field-management decisions early in field development.

**Evaluating Fractures and Fields**

There are many different ways to characterize natural fractures and to evaluate their role in reservoir exploitation. Dynamic methods seek to characterize the effects of fractures by measuring or directly describing the movement of fluids through fractures and matrix. These dynamic methods include medium-scale interval, pressure-transient testing, which provides information on fractures and fracture-related flow, and estimates of fracture conductivity. These tests can be obtained with the MDT Modular Formation Dynamics Tester. Another medium- to large-scale dynamic method uses injected tracers and water-composition analysis to determine direct communication attributed to fractures between zones and between wells.

19. Stylolites are wave-like or tooth-like, serrated, interlocking surfaces, most commonly seen in carbonate and quartz-rich rocks, that contain concentrated insoluble residue such as clay minerals and iron oxides. Stylolites are thought to form by pressure solution, a dissolution process that reduces pore space under pressure during diagenesis.


Cross section of a stylolite. Stylolites are diagenetic features commonly found in low-permeability carbonate rocks. They form as irregular surfaces between two layers and are generally thought to be the result of pressure solution under a state of differential stress. Stylolites normally inhibit subsurface fluid flow, but are often associated with small fractures called tension gashes, which sometimes appear permeable on core tests.

Naturally fractured reservoir classification system. Type 1 reservoirs, with fractures providing both primary porosity and primary permeability, typically have large drainage areas per well, and require fewer wells for development. These reservoirs show high initial production rates. They are also subject to rapid production decline, early water breakthrough and difficulties in determining reserves. Type 2 reservoirs can have surprisingly good initial production rates for a low-permeability matrix but can have difficulties during secondary recovery if the communication between the fracture and the matrix is poor. Type 3 reservoirs are typically more continuous and have good sustained production rates but can have complex directional permeability relationships, leading to difficulties during the secondary-recovery phase. Type M reservoirs have impressive matrix qualities but are sometimes compartmentalized, causing them to underperform compared with early producibility estimates, and making secondary-recovery effectiveness variable within the same field. Type 4 reservoirs would plot near the origin because the fracture contribution to permeability in Type 4 reservoirs is negative. (Adapted from Nelson, reference 1: 102.)
Geometric methods measure specific attributes to identify and characterize natural fractures and assess their potential impact on production or injection. While traditional logging measurements, such as caliper and microresistivity logs, can allude to the presence of natural fractures, they are generally not quantitative. Today, various technologies have been developed to address NFRs. The most common small-scale, log-based fracture-evaluation techniques use ultrasonic and resistivity borehole imaging technologies that can be deployed by wireline or LWD methods.

While the resolution of wireline-conveyed electrical borehole imaging tools is exceptional, the most detailed way to assess NFRs is by acquiring fullbore cores across intervals of interest. Having access to fullbore core allows geologists and petrophysicists to examine specific properties that influence a fracture’s ability to conduct fluids—for example, the presence of infilling minerals. Another extremely valuable use of core data is to provide a “ground truth” from which to calibrate other fracture-analysis methods. However, fullbore coring can be expensive and poor core recovery can be a problem in highly fractured rock. Also, coring-induced fractures can be difficult to distinguish from unmineralized natural fractures. Despite the difficulties, there are now innovative ways to characterize NFRs using advanced technologies and processing techniques.

The fractured granite basement rocks of the Cuu Long basin, offshore Vietnam, are mostly Type 1 reservoirs—both porosity and permeability in the basement rock are provided by natural fractures (left). However, in the fractured zones surrounding faults, secondary porosity has been documented because hydrothermal fluids dissolve feldspars in the matrix. The result is a hybrid Type 2/Type 1 NFR.

Since first production in the early 1990s, common methods for measuring permeability—the most daunting property to ascertain in these fractured basement reservoirs—were performing well tests or acquiring and testing core. Well-test analysis of fractured reservoirs requires numerous assumptions that can lead to errors, while core analysis is typically pessimistic because the most highly fractured reservoir intervals often are not recovered and analyzed.

Even though Cuu Long reservoirs rely solely on fractures to produce, their productivity can be astonishing—some individual wells can produce more than 20,000 bbl/d [3,180 m³/d] of oil. A series of geologic episodes, including an extensional phase during rifting, which created the basin, followed by two major phases of compression, has led to a complex but prolific natural-fracture network that can be divided into three fracture classes—solution-enhanced and unenhanced bounding fractures, straight-walled fractures and discrete fractures (next page, left).

When not filled with clays, calcite and zeolites, the bounding network of fractures forms the main conduits for fluid transmission and provides important storage volume for the basement reservoirs. Some of the bounding fractures are enormous, measuring more than 1.5 m [4.9 ft] in fracture width. On the other hand,
the majority of discrete fractures are relatively short, terminate at the bounding fractures, contribute the majority of the storage capacity to the bounding networks, and maintain apertures that mostly range from 0.01 to 0.1 mm [0.0004 to 0.004 in.].

In the fields of the Cuu Long basin, permeability is the driving factor for well productivity. Using FMI image data, geoscientists from Schlumberger, Cuu Long Joint Operating Company (JOC) and VietSovPetro developed a method to consistently calculate reservoir permeability and calibrate it to core analysis, well-testing results and production-log data. First, fracture interconnectivity is assessed using the image data and the BorTex texture classification tool in the Schlumberger GeoFrame integrated reservoir characterization system platform. This processing essentially maps out the conductive anomalies within the resistive granite matrix on the borehole image and computes a relative permeability indicator (RPI).

In another processing step, fracture apertures and fracture density are calculated for hand-picked fractures on the FMI resistivity images. These outputs, along with a calibration constant, are used to calculate fracture permeability ($K_f$). In Type 1 reservoirs, $K_f$ should equal reservoir permeability ($K_r$) for the same investigated volume. The RPI can then be scaled to $K_r$ to provide a continuous assessment of permeability. The limited amount of core taken in a zone of relatively low permeability was used to calibrate $K_r$ (above right).

This image-based interpretation technique has been successful on numerous wells across the Cuu Long basin. For example, on one well, 300 m [984 ft] of the granite basement rock was penetrated at a top depth of around 3,900 m [12,800 ft]. A standard openhole-logging suite was acquired along with FMI images and only 3 m [9.8 ft] of fullbore core. After initial production, dynamic fracture-characterization methods were employed on two occasions—shortly after the well was completed and again after 17 months of production—and included well testing and production logging.
A correlation between the calculated permeabilities and actual reservoir performance was very good (below). Initially, oil flowed from three zones as demonstrated by the production log, but there were several high-permeability zones that did not contribute. Experts at Cuu Long JOC and VietSovPetro suspected that the lack of contribution was caused by partial formation damage, since mud losses were recorded during drilling, for example from X,090 to X,100 m. Reassuringly, after 17 months of production, other zones began to contribute to production. Over time, the damaged zones cleaned up with assistance from the pressure drop in the wellbore. In addition, the water cut had increased since the start of production.

This technique has helped to minimize the complicating effects that resistive fracture-filling minerals have on fracture characterization in the fields of the Cuu Long basin. However, conductive minerals in the fractures, found mainly in weathered zones at the top of the granite, still pose a dilemma because resistivity-based imaging tools cannot differentiate between conductive minerals and conductive drilling fluid. In these zones, special attention is paid to corroborative data—mud-loss records, gas shows and log data from the MDT or CMR Combinable Magnetic Resonance tools. Importantly, this fracture-characterization technique provides a detailed, depth-continuous permeability output that can help asset teams with individual well stimulation and completion and injection designs, and can be upscaled to reservoir models across an entire field.

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<th>Caliper</th>
<th>Gamma Ray</th>
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<th>Bulk Density</th>
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^ Integrated fracture permeability analysis showing a comparison of computed permeability to production logging and well-testing results. Standard openhole-log data are displayed in Tracks 1 and 2, FMI images are shown in Track 3, fracture apertures calculated from the FMI data are presented in Track 4, Kf and RPI are shown in Track 5, and Kr with core-calibration points is displayed in Track 6. The yellow box in the Depth Track indicates the location of significant mud losses during drilling. Tracks 7 and 8 include the interpreted production-log results in the first well-testing job shortly after the well was drilled. Track 9 presents the interpreted production-log rate, showing zones that contributed water (blue) and oil (red) from the second well-testing job, performed after the well had been on production for 17 months.
Fractures in the Rocky Mountains

Hydrocarbon production from low-porosity, low-permeability, hard-rock reservoirs depends on successfully connecting open fracture networks to the wellbore. Because the matrix quality is generally low, the surface area exposed to the wellbore along fracture planes often must be increased for required production volumes. This is accomplished by performing hydraulic fracture stimulation. Open natural fractures contribute to production but can also cause problems during drilling, cementing, completion and stimulation operations. Therefore, it is essential to identify fractured intervals for cement- and stimulation-staging considerations.

A powerful combination of high-resolution borehole imaging and innovative acoustic measurements from the Sonic Scanner acoustic scanning platform adds dynamic elements to detailed fracture analysis from wireline tools. Schlumberger geoscientists and petrophysicists in the Rocky Mountain region, USA, use Stoneley and dipole flexural-wave data from the Sonic Scanner tool and FMI image data to clearly identify formation bedding, sedimentary features and fractures. The improved low-frequency Stoneley response—down to 300 Hz—of the Sonic Scanner tool enables the detection of high-angle to vertical fractures. Also, using an attenuation technique called normalized differential energies (NDE) makes it possible to differentiate natural fractures from drilling-induced fractures, even when they are oriented in the same direction—usually parallel to the present-day maximum horizontal-stress direction. However, when the stress-related anisotropy direction differs only slightly from the fracture-induced anisotropy direction, the new tool is still able to differentiate the two because of the improved ability to resolve small amounts of anisotropy—now 2%, versus 5% with the previous technology.

Frequency-content and signal-strength variations occur in naturally fractured intervals. Another processing technique called slowness-frequency analysis (SFA) allows the interpretation of dipole flexural-wave frequency and amplitude data and shows the quality of the estimation of shear slowness from flexural-wave dispersion analysis up to several feet into the formation from the wellbore.

In the Type 2 reservoirs in the Rocky Mountains, porosities range from 3 to 7% and matrix permeabilities are in the microdarcies. The FMI tool enables the calculation of fracture aperture, fracture porosity, fracture density and fracture trace length at the wellbore. Combining independent fracture-characterization methods from the Sonic Scanner Stoneley-wave and shear-wave analysis with FMI image interpretation shows an unambiguous assessment of fracturing across the interval (above). Armed with this log-based characterization of the fractures, the asset team can better judge the optimal way to cement, complete and stimulate this potentially productive interval.

Experts in the Rocky Mountain region have developed a hard-rock completion solution that combines Sonic Scanner data with FMI data to optimize hydraulic fracture design. The solution incorporates natural-fracture characterization—including the determination of fracture aperture, fracture permeability and fracture extent—and the analysis of maximum and minimum horizontal stresses. All this information is captured in the mechanical earth model that is used by stimulation designers to optimize hydraulic fracture design.

Coalbed Methane Reservoirs

There may be no other NFR as difficult to stimulate as a coalbed methane (CBM) reservoir, an unconventional but growing source of methane. Beginning with its deposition as peat, coal is a unique reservoir rock. To be productive, coalbed reservoirs require natural fractures. Vertical natural fractures in coal are called cleats, and these form during coalification. Systematic coal cleats are classified geometrically with the primary, more continuous fracture set called face cleats and the secondary, less continuous fracture set called butt cleats (below).

Coal fractures can also be classified genetically. Endogenetic fractures, or classic cleats, are created under tension as the coal matrix shrinks because of dewatering and devolatilization during coalification. These cleat sets are orthogonal and nearly always perpendicular to bedding. In contrast, exogenetic fractures form due to tectonism, and regional stress fields dictate their orientation. Shear fractures also are observed in some coals. Cleats are the primary permeability mechanism in virtually all CBM reservoirs, so understanding cleating and natural fracturing in coals is critical during all facets of CBM reservoir development.

Methane is stored in coal by adsorption, a process by which the individual gas molecules are bound by weak electrical forces to the solid organic molecules that make up the coal. Coal’s ability to store methane largely reduces

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Examples of Canadian coals on FMI images and outcrops. The FMI image (top left) and a photograph from a representative outcrop (bottom left) of the Alberta Plains coal show both face and butt cleats. Shear fractures, face cleats and butt cleats are shown on both the FMI image (top right) and the outcrop photograph (bottom right) of the Alberta Foothills coal. Interestingly, shear fractures usually degrade coal permeability.
the need for conventional reservoir-trapping mechanisms, making coal’s gas content—which increases with increasing coal rank—and the degree of cleating or natural fracturing the overriding considerations when assessing an area for CBM production potential.

This storing ability gives coals unique early-time production behavior that is related to desorption, not pressure depletion. Coals may contain water or gas, or both, in the cleat and natural-fracture systems, in addition to gas sorbed onto the internal surface of the coal matrix. Any water present in the cleat system must be produced to reduce the reservoir pressure in the cleat system before significant volumes of gas can be produced. Dewatering increases the permeability to gas within the cleats and fractures, and causes the gas in the matrix to desorb, diffuse through the matrix and move into the cleat system, resulting in CBM production profiles that are unique by comparison with other fractured reservoirs.

In most CBM reservoirs, water production is initially high. As the water moves out of the cleats and fractures, gas saturation and production increase and water production decreases. The speed at which the reservoir dewaterers depends on several factors, including original gas and water saturations, cleat porosity, relative and absolute permeability of the coal, and well spacing. When permeability to gas eventually stabilizes, the coal is considered dewatered and gas production peaks. From this point, both water and gas production slowly decline, with gas being the dominant produced fluid.

In just a few years of development, CBM gas production in Alberta, Canada, has surpassed 300 million ft³/d [8.50 million m³/d]. Most of this production comes from the Horseshoe Canyon and Mannville coal zones, and a small percentage—less than 1%—comes from the Ardley coals in the Upper Cretaceous Scollard formation (above). The less-exploited Ardley coals, however, are a significant potential CBM resource, exceeding 40 trillion ft³ [1.13 trillion m³].

Burlington Resources, now ConocoPhillips, has investigated the Ardley coals using the FMI tool. In two wells, the borehole images have allowed geoscientists at ConocoPhillips and Schlumberger to determine the present-day stress regime from drilling-induced fractures, which are oriented northeast to southwest, in the direction of maximum horizontal stress. This direction is consistent with previous assessments. The FMI images have also provided insight into the nature and direction of

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cleating within the Ardley coals—the Val D’Or, the Arbour, the Silkstone and the Mynheer zones (above). Interpretation of FMI images suggested that within the Scollard formation, the Silkstone coal had the most productive potential and the Arbour coal had some potential.

ConocoPhillips integrated public and proprietary cleat-orientation information from mines and outcrops. In addition, geoscientists performed a detailed examination of six unoriented conventional cores that were cut from the Ardley coals five to ten years earlier. To supplement the regional study of Ardley coal cleating, these cores had to be oriented after the fact, years after their acquisition. To accomplish this, ConocoPhillips utilized a technique developed by Applied Paleomagnetics called paleomagnetic core orientation, which requires that whole cores be reassembled and that plugs cut from the core be selectively demagnetized. The cores are oriented using the secondary magnetization of magnetite found in nearly all rocks. This magnetization points to present-day geographical north and represents the average geomagnetic field over the past 780,000 years, which is the time since the last geomagnetic polarity reversal. Once the north direction on the core is determined, a sample is cut from the core and selectively demagnetized. This process is repeated for each sample, and the core is reassembled using the north direction of each sample.

36. Fracture intensity is a qualitative description of the degree of natural fracturing that is usually derived from seismic traveltime attributes.
reassembled core is determined, the results from the detailed analysis can then be oriented, yielding orientation data comparable to outcrop and mine studies and FMI image analyses (right).

All sources of data indicated that a dominant northeast-to-southwest face-cleat system might be open because of its favorable alignment with the present-day maximum horizontal stress. The butt-cleat system in the Ardley coals is much less persistent and is aligned less favorably with respect to present-day stresses. The lack of butt cleats in Ardley coals is in contrast to Horseshoe Canyon and Mannville coals.

Horizontal wells drilled perpendicular to the face-cleat system may require hydraulic fracturing of multiple intervals within the horizontal section to effectively stimulate the coals and optimize production potential. A more effective stimulation promotes the dewatering of the cleat systems and speeds up gas desorption. The challenging permeability scenario will also influence well-design considerations, such as drilling updip to maximize drainage.

Exploration for coalbed methane in the Ardley coals of the Scollard formation is in its infancy. ConocoPhillips plans to integrate the results of this cleat study with hydrogeological and structural interpretations to develop its future exploration strategy.

A Seismic Net to Capture Fractures
The ability to characterize fracture systems in the early field-development stage reduces economic risk because it enables asset teams to determine optimal horizontal well directions to maximize production and recovery. So far, most of the discussion on fracture characterization has dealt with the investigation of fractures using relatively high-resolution techniques as compared to seismic methods, which use wavelengths up to 100 m (328 ft) to detect the presence of natural fractures using azimuthal anisotropy analysis. These techniques do not detect individual faults or fractures, but rather exploit the average response across a large volume of rock. For example, measuring travelt ime differences between the fast and slow shear waves, together with the polarization direction of the fast shear wave, helps to infer the fracture intensity and fracture orientation, respectively. Seismic fracture-characterization methods include velocity anisotropy determination, azimuthal amplitude variation with offset, and normal moveout (NMO) variation with azimuth.

Seismic azimuthal anisotropy methods. The diagrams show land and marine seismic acquisition methods used to detect fracture-induced anisotropy. The fracture diagram (top left) shows vertical fractures striking north-south in the example, causing shear-wave splitting that helps determine the fast-shear direction (north-south red polarization vectors) and the slow-shear direction (east-west blue polarization vectors). The sinuroid shows how anisotropy can be determined from compressional and shear velocity variations with azimuth (top right). The land seismic diagram (bottom left) shows the rays for common midpoint gathers from two source-receiver directions. The seabed seismic diagram (bottom right) demonstrates the effects of seismic anisotropy by showing two rays: a south-going fast ray from a source position to the north of the seabed receiver cable; and a west-going slow ray from an east source position above the seabed receiver cable. In 3D surveys, all azimuth directions are interrogated.
Seismic investigations of NFRs include those from multioffset, multiazimuth vertical seismic profiles (VSPs). Walkaway- and walkaround-VSP techniques permit velocity anisotropy and amplitude variation with offset and azimuth (AVOA) analyses at higher resolutions than with surface seismic methods and can be used to calibrate other seismic results. Integrating all available data to optimize the VSP configuration is important for extracting high-quality anisotropy information. This information can then be used to design 3D surface seismic surveys to cover areas remote from well control.14

Through the years, geophysicists have noted that compressional- (P-) wave velocities exhibited azimuthal variations when processing some 3D seismic surveys, especially those in areas of high tectonic stress.15 The fast P-wave direction aligns with the maximum compressional stress direction, parallel to natural fractures resulting from the stress. In this simple scenario, the slow P-wave direction would be aligned perpendicular to the fracture strike, and the fracture-filling fluid would affect the velocity. Azimuthal variations in other seismic attributes, such as reflection amplitudes, have also been observed and exploited to determine fracture azimuth.

The advantage of examining amplitude variations is that it detects local azimuthal variations in contrast to velocity-based techniques, which respond to the accumulating effects of overlying strata.16 Consequently, AVOA analysis is a higher vertical resolution depiction of a NFR than that obtained with velocity-based methods. Reflection amplitude, or reflectivity, depends on the effective elastic properties of the fractured rock at the seismic scale. Because both P- and shear (S-) velocities change with azimuth in a fractured medium, an AVO response will be influenced by fracture properties, including fracture azimuth. While AVOA processing and interpretation are fairly simple where there is a single alignment in an otherwise homogeneous medium, multiple fracture directions— for example near faults—and additional sources of anisotropy may significantly complicate the analysis.17

Another approach examines the azimuthal variation of P-wave normal moveout (NMO) velocity.18 A minimum of three azimuthal measurements is required to construct an ellipse in the horizontal plane that shows NMO velocities in all azimuthal directions. Although most seismic fracture-analysis methods assume a simple geometry—horizontal beds and vertical fractures—the NMO technique allows some further assessment where beds are dipping and where natural fractures may not be vertical. However, this technique also suffers from velocity-related degradation of vertical resolution.

A carbonate reservoir study in a field in southwest Venezuela compared seismic-based fracture-orientation results with fracture orientations based on FMI images.19 Different seismic data types were used in the study, including 2D three-component (3C) P- and S-wave data, and 3D P-wave data. The study found that most of the results from the rotation analysis of the converted-wave 2D-3C data, and the AVOA and NMO analyses of the 2D and 3D P-wave data determined the general direction of the regional maximum horizontal stress. However, results varied between the different methods because of local structural variations. With the 3D P-wave data, the AVOA technique appeared more robust than the NMO analysis. The Venezuelan study also found that there were quantifiable advantages to acquiring land 3C data, including the ability to estimate fracture orientation and fracture density, or intensity.

Acquiring multicomponent seismic data in a marine setting requires sophisticated four-component (4C) seabed acquisition equipment.20 Marine seismic studies have been successful in identifying anisotropy direction and magnitude at the specific target horizon by effectively removing the influence of the overburden in a layer-stripping approach.21

Passive seismic methods that detect the reservoir response to production or injection can also be thought of as dynamic fracture- and fault-characterization techniques. Natural fractures and faults emit microseismic events—mostly due to shear readjustments—in response to changes in effective stress following field production and injection, and especially during hydraulic fracture stimulation operations.22 Sensitive seismic sensors positioned in nearby wellbores detect these acoustic emissions, which in this method serve as the seismic source (above). Special processing methods estimate event locations, producing a continuous time-based record of production- or injection-induced activity. Seismic methods represent medium- to large-scale fracture detection and characterization methods, and therefore have implications in the effort to model the interwell volume of these complex reservoirs.
Regardless of the technique, information cultivated from seismic data contributes to reservoir modeling that guides primary- and secondary-recovery planning. However, in many fields, wells from which to draw detailed fracture information are too few and too widely spaced to populate the model volume. Geologists gather detailed fracture data—orientation and possibly spacing—from analog outcrops. However, this process rarely captures a comprehensive description of the fracture network for modeling purposes and sometimes overestimates fracture intensity.

Geoscientists at Hydro and Schlumberger in Norway have developed a way to capture the detailed quantitative information needed to make NFR models from outcrop analogs. This method uses a combination of high-resolution optical photography, radar technologies and an automatic surface-extraction technique now widely used for mapping faults in 3D seismic datasets.\(^4\) Hydro and Schlumberger experts have tested this new technique using a well-studied NFR outcrop analog in the Guadalupes Mountains, New Mexico, USA.

For several years, Hydro, together with the University of Texas at Dallas, has been using detailed 3D photorealistic models for high-resolution mapping of outcrop analogs.\(^4\) Photorealistic models are derived from the mapping of high-resolution 2D photographs onto 3D outcrop scans using light detection and ranging (LIDAR) technology.\(^4\) LIDAR equipment transmits laser light—visible electromagnetic radiation—to a target and receives back the reflected signal for analysis to determine certain properties of the target. The most common type of LIDAR is used for precise range finding—accurate to 2 mm [0.08 in.].—and the returned radiation intensity can help define other characteristics of the target.

Digitizing sufficient detail of sedimentary architecture from photorealistic models for the building of reservoir models is a straightforward process. However, manual digitizing and analysis of fractures from these datasets is impractical, because several hundred thousand to millions of fractures are commonly present. The new automated approach to outcrop mapping is organized to take advantage of the 3D directional information inherent in LIDAR data and couple it with the detailed information within high-resolution 2D image data. To achieve this, the LIDAR and photographic data are first analyzed separately. Because the outcrops naturally weather along fractures, fault planes and bedding, the major fracture sets and bed boundaries are captured by vector analysis of the LIDAR data (above left). The orientations of target


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surfaces are described using the three directional components of the normal vector. Radiation intensity is then corrected for both the distance to the LIDAR apparatus and the angle of the outcrop surface. A 3D LIDAR model grid is created and populated with the directional and intensity data. The corrected LIDAR intensity and directional-component data can then be partitioned into value ranges for mapping and analysis.

Although there is good detail in the LIDAR data, an even higher level of information is contained in the photographs (above). However, before an automated structural interpretation of the photographic data is accomplished, the digital image must be filtered for noise—anything in the image that does not represent part of the rock exposure, such as vegetation or scree.

Next, an attribute or combination of attributes is selected and the Automated Structural Interpretation process, adapted from what is now used in Petrel software, can begin enhancing surfaces. The process uses an adaptation of the technique developed for fault interpretation in 3D seismic volumes. At first, a fault or fracture may appear only as a trend within the data, but as signal-to-noise characteristics are improved along the surfaces, a more defined plane is mapped by “agents” using the principles of “swarm intelligence” (next page). A large number of process agents are deployed in the data volume, making decisions based on precoded behavior. Like ants, the agents traverse the various surfaces emitting an “electronic pheromone” along the trail, from which an estimate of the surface orientation is made and stored; in this case fractures and bedding are


picked. The result is a 2D map of linear outcrop features—mostly fractures and bedding—but at a higher resolution than that extracted from the LIDAR data.

Once the innovative processing is made on the high-resolution digital photographs and LIDAR data, the results are recomposed into the 3D photorealistic model for manual verification and analysis. At this stage, the 2D maps derived from the photos are transformed into 3D data as they are projected onto the photorealistic outcrop model as a series of planes and attributes. The results of the photographic and LIDAR analysis are displayed as attributes in an editing window, and compared to the photorealistic model by the interpreter for quality control.

Following editing of the data, the structural geologist is able to begin the process of quantitative fracture interpretation. Because bedding is automatically mapped as a part of the process, the interpreter is able to perform quantitative analysis of fracture extent, density and orientation on a layer-by-layer basis, thus establishing a mechanical stratigraphy. The analyzed joint planes and their relationship to bedding and faults can then be used as the basis for a discrete fracture network model. Such models can be analyzed in terms of representative fracture volumes and flow heterogeneity related to the fracture systems.

**Modeling the Effects of Fractures**

There are perhaps no other simulation tasks as challenging in today’s oil and gas fields as constructing valid NFR models to simulate reservoir fluid flow with a reasonable degree of certainty. The challenges span multiple disciplines and multiple scales, and must always be addressed with limited information. The ultimate aim in reservoir simulation is to estimate and predict the distribution and flow of fluids within the reservoir in response to production or injection. Natural fractures make achieving this aim considerably more difficult.

Some experts simplify the challenges of NFR fluid-flow simulation into three categories. First, a model must resolve the fluid pathways by determining fracture connectivity. Connectivity depends on fracture length, orientation and intensity, which come from subsurface data and outcrop analogs. Second, knowledge of fracture-system permeabilities, permeability variation across the field, and the interaction between fractures and the matrix is essential. Third, the fluid pressure, or capillary pressure, and the relative permeabilities in the reservoir must be captured. Additionally, a good understanding of the in-situ stress regime is needed for credible NFR simulation. This information comes from a variety of sources—including logging measurements, borehole breakout and leakoff tests—and is used in mechanical earth models.

The complexity of NFRs represents a real challenge in reservoir simulation. The most geologically realistic models are discrete fracture network (DFN) models. In these models, each fracture is represented as a plane in the reservoir with attached properties such as aperture and permeability. DFNs are able to represent the geometric complexity of fractured reservoirs with a high level of detail. Fluid flow can be simulated through DFNs using finite-element methods, and the effects of matrix flow can also be incorporated.

Creating a plausible model, however, places great demands on geoscientists, and the fracture system must be parameterized in all its detail. This model is typically built from high-quality data near wellbores—for example, borehole image data, core analysis and pressure-transient data—and is expanded to the interwell region using geostatistical techniques. DFN models can also be guided by seismic anisotropy fracture-characterization results and production data. Well and seismic data are generally not sufficient to provide information about fracture extent and connectivity and so outcrop analogs become crucial sources of information.

Today, the generation of DFNs still has limitations. DFNs are computationally intensive, so it is not possible to model all of the fractures within a reservoir in this way. While a DFN could be used for an individual well test history-match, commercially available DFNs can handle only single-phase flow and thus cannot model secondary-recovery mechanisms. It is possible to represent only the largest fractures geometrically in cellular models, while smaller fractures have to be represented as modified cell properties. However, the physics of flow between fractures and matrix in cellular models can be represented using the finite-difference method and using dual-porosity and dual-porosity/dual-permeability techniques.

It is difficult to provide a link between the geologist’s view of a fractured reservoir and a cellular representation. One method for dealing with this problem is to create small-scale DFN models that represent the details of the fracturing and to upscale them to cellular grid blocks using either static or dynamic methods. For example, a joint system was mapped from a...
Streamline simulation. Streamline simulators, such as the ECLIPSE FrontSim software, allow reservoir engineers and geoscientists to quickly simulate fluid flow in heterogeneous reservoirs. These simulators are especially useful when simulating the effects of fractures or other high-permeability conduits on waterflooding for secondary recovery. In this example, the streamlines and reservoir layers are color-coded according to water saturation, $S_w$.

A constant aperture was assigned to the fractures, and the permeability was upscaled using a pressure solver. The upscaled permeability in the X-direction, Block $K_{xx}$, is scaled according to the color bar (left). Histograms (bottom) show Block $K_{xx}$ and the fracture porosity for each 10-m by 10-m [32.8-ft by 32.8-ft] cell. The rose diagram (top right) shows the orientation of 1,669 fractures interpreted by what is now the Petrel Automated Structural Interpretation process.

Fracture Porosity

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Typically, models are tested and calibrated using historical pressure and production data—history-matching—and must be updated and fine-tuned with new information. An asset team’s ability to quickly update reservoir models and run multiple simulations has been enhanced, and continues to improve, with the availability of increased computing power.

Fracture Breakthroughs
Some of the largest hydrocarbon reservoirs in the world are naturally fractured carbonate reservoirs in the Middle East, Mexico and Kazakhstan. In many cases, these reservoirs have three porosity systems: fracture, matrix and vuggy—both connected and isolated—and involve multiphase fluid flow, adding to the modeling difficulties. The challenges facing operators in these fields are daunting. Declining hydrocarbon productivity, increasing water production and significant volumes of unswept oil are the most obvious reasons for concern. Closer examination has revealed inherent difficulties in modeling heterogeneous, dual- and triple-porosity reservoirs with multiphase fluid flow. In these cases, it has been useful to develop special relationships for relative permeabilities and capillary pressure that take the complexities into account.

On March 25, 2006, Schlumberger, in an alliance with King Fahd University of Petroleum and Minerals, officially opened the Schlumberger Dhahran Center for Carbonate Research (SDCR) to engage in collaborative projects focusing on carbonate reservoirs, the majority of which are NFRs. Scientists at this state-of-the-art research center will focus on the development of technologies that address the challenges of exploiting these complex reservoirs, including research in land seismic technologies, geology, rock physics and fluid dynamics.

In the past, available static and dynamic data have dictated an asset team’s approach to NFR characterization, modeling and simulation. Today, a better understanding of NFR complexities, improved measurements and interpretation techniques across a wider range of scales, faster and vastly improved modeling capabilities and exciting new research will make the industry’s progress in fractured reservoirs natural. —MGG
Oilfield Technologies for Earthquake Science

Deep within an active fault zone, the San Andreas Fault Observatory at Depth will measure changes in rock properties before, during and after earthquakes. Linked with other measurements at the Earth’s surface, these direct observations will, for the first time, monitor how an active fault and the surrounding environment respond to local and regional changes in stress. This combination of measurements, recorded over the next decade, will provide important new insights on how earthquakes form and how they rupture.

Most of us rarely think about the forces that formed the natural beauty of our national parks or produced our natural resources. Only when earthquakes rattle communities or create huge tidal waves that flood coastal communities are we jarred into considering the momentous forces that fashion the terrain upon which we live, work and play.

On Sunday, December 26, 2004, a strong earthquake of magnitude 9.3 on the Richter scale occurred off the coast of northern Sumatra. This event triggered a giant tsunami that propagated throughout the Indian Ocean basin, causing massive destruction—more than 250,000 casualties and damage in excess of US$ 4 billion.
Many of the world’s worst natural disasters are the result of earthquakes. The largest earthquake of the past century was the massive magnitude 9.5 event that struck Chile in 1960, ultimately leading to more than 2,000 deaths. The deadliest earthquake in recent history was a magnitude 8.0 event that struck Tangshan, China, in 1976, killing more than 240,000 people.

This year marks the centennial of the most destructive US earthquake, the 1906 magnitude 7.7 San Francisco earthquake. The disaster, caused by movement along the San Andreas Fault, resulted in fires that led to an estimated 3,000 deaths and more than US$ 500 million in property losses. The San Andreas Fault is the surface expression of one of the major transform-fault, plate-tectonic boundaries of the world. Here the Pacific Plate moves horizontally to the northwest about 5 cm [1.9 in.] per year relative to the North American Plate. The people on the western coast of the USA, especially those in the heavily populated coastline cities of California, are dangerously situated directly over areas with the highest risk of seismic activity (previous page).

The social and economic impact of these natural disasters has increased our need to forecast when major earthquakes will likely occur—just as meteorologists forecast weather. This article discusses the construction of the first underground earthquake observatory on the San Andreas Fault. The mission of the observatory, called the San Andreas Fault Observatory at Depth (SAFOD) is to study factors that affect earthquake physics. In this article, we will briefly outline how oilfield technologies are being used to build the observatory, discuss some of the scientific objectives of SAFOD, and describe how oilfield geophysical measurements are helping scientists unravel some of the surprises discovered so far.

EarthScope and SAFOD

The great San Francisco earthquake of 1906 is said to have given birth to modern earthquake research. SAFOD, the latest endeavor, is part of a five-year, US$ 200 million nationwide scientific program called EarthScope. The project, a US National Science Foundation (NSF) initiative, will investigate the structure and evolution of the North American continent and the physical processes that generate earthquakes. For the NSF, an understanding of what happens at the point where earthquake activity begins is one of the ultimate goals of seismology.

1. The Richter scale is used to rate the magnitude of an earthquake, which is calculated using data gathered by a seismograph. The Richter scale is logarithmic, meaning that whole-number jumps indicate a 10-fold increase in seismic-wave amplitude. For example, the wave amplitude in a magnitude 6 earthquake is 10 times greater than a magnitude 5 earthquake. The energy released increases 31.6 (scaled as $10^{2/3}$) times between whole number values. For more on earthquake magnitudes: http://www.answers.com/topic/richter-magnitude-scale (accessed May 9, 2006).
2. The 1994 earthquake in Northridge, California, was even more costly, with estimated losses over US$ 20 billion.
3. Earthquakes occur when rocks being deformed suddenly break along a fault, setting off waves of ground vibrations. Such slippage usually occurs at plate boundaries. The theory of plate tectonics was introduced in 1968 by geologist J. Tuzo Wilson and others.
Stanford University and the US Geological Survey (USGS) provided SAFOD with teams of scientists from industry and national and international universities, including geologists, geophysicists and seismologists. The Stanford and USGS team led the drilling and casing of a 4-km [2.4-mile] well across the San Andreas Fault (SAF). Since the 1906 San Francisco earthquake, this fault has become a primary focus of earthquake studies in the USA. This well is being instrumented as a scientific observatory.

The SAFOD well is placed at a depth greater than 3 km [9,840 ft] to ensure the detection of repeated magnitude 2 earthquakes. Hunting bigger earthquakes would require drilling much deeper; for example, most magnitude 6 earthquakes originate about 6 miles [10 km] below the surface.

The SAFOD drill site, located in central California along a creeping zone of the SAF, was chosen for two key reasons. First, it is a location with many magnitude 2 earthquakes that repeat approximately every two years. Second, the SAFOD site is situated at the most studied earthquake locality in the world—Parkfield, California. Since its inception in 1985, the “Parkfield experiment” has involved many researchers at the USGS and collaborating universities and laboratories.

This experiment uses a large network of 70 geophysical stations that take measurements from various seismic, geodetic ground positioning, electromagnetic and water-level monitoring instruments to observe different types of earthquake phenomena in the region. These efforts have provided a wealth of key seismological, geologic and surface geophysical information used in preparation for the SAFOD drill site. After years of study, the Parkfield scientists concluded that they needed to look inside an active fault to monitor the occurrence of earthquakes.

Currently, SAFOD is in the construction and “discovery” stage of development. The pilot hole, drilled in 2002, was used for two years as a base for extensive geophysical studies in the Parkfield area. Seismometers installed by the Stanford and USGS team, in collaboration with Oyo Geospace and Duke University, measured earthquakes in the pilot hole between 2002 and 2004. The seismometer data, along with well logs, cuttings data and core analyses helped seismologists plan the main borehole trajectory. The first section of the main borehole, called Phase 1, was drilled to a depth of 2.5 km [8,200 ft] between June and September 2004. The second section of the borehole, Phase 2, extended the well almost 800 m [2,625 ft], and was completed through the San Andreas Fault in October 2005 (left).

University and USGS scientists are intensively studying data from these initial construction phases of the main borehole. Phase-2 drilling included revisions in well trajectory based on improved estimates of target earthquake locations. Better estimates of earthquake locations were achieved through bottomhole seismometers deployed in the SAFOD well at the end of Phase 1. Placing seismometers closer to the earthquake source provided a more accurate estimate of seismic velocities between the seismometer and target earthquake. Better velocity information improves imaging using acoustic wavefields and ultimately improves earthquake-targeting accuracy. Finally, the 2007 Phase-3 drilling will place multilateral boreholes into several active earthquake patches. Subsequently, a 15-year period of earthquake monitoring and study will begin.
Throughout this project, there have been extensive industrial and academic collaborations and contributions. Contributions from industry were provided by exploration, production and service companies, including drilling support, coring, well logging, logging-while-drilling services, and scientific and engineering support. For example, Schlumberger provided instruments for high-resolution seismic surveys, earthquake-monitoring and other geophysical recording instrumentation. Furthermore, experts from major oil companies, including Shell, BP, ExxonMobil and ChevronTexaco, are serving as members of SAFOD’s technical advisory board, helping to plan and make critical engineering decisions needed to construct the observatory.

**Key Scientific Questions**

So far, scientists have not been able to predict earthquakes reliably. To determine if such a goal is possible, they need an improved understanding of the physical processes that occur in the fault zone before, during and after earthquake events.

When completed, the SAFOD site will be the only earthquake observatory with instruments installed directly within an active fault. SAFOD will thus enable scientific observation of the nucleation process in which faults suddenly slip and create the seismic energy we know as earthquakes.

Despite years of study, many questions about earthquakes remain unanswered. What causes earthquakes? What dynamic subsurface processes cause faults to slip? Do they start suddenly without warning—or are they preceded by a period of slow slip in the fault zone that stresses the fault zone before it breaks? Might high-pressure fluids be injected into the fault zone, allowing separation of rocks along the fault before the earthquake starts and ruptures propagate through the subsurface? Does an earthquake start as a small pinpoint, which then continues to grow? Do small earthquakes grow just a little, while big earthquakes grow more?

From laboratory experiments and surface observations, geoscientists have postulated several theories concerning earthquake initiation. Some theories involve a fault “preparation zone” with highly stressed areas that determine how large an earthquake will become. Other theories assert that subsurface fluid pressure affects the nucleation of earthquakes. There are also theories that exotic minerals with low coefficients of friction contribute to earthquakes.

All these theories have some basis in field observations at the surface or in the laboratory, but they have never been tested in an active fault. With instruments installed in the SAFOD well, scientists will finally be able to closely monitor earthquakes in the “near field” of seismic-wave propagation to address some of their theories.

SAFOD research also studies dynamic issues relating to what happens in the minutes, hours, days and even years before an earthquake occurs. There is much debate about this. In laboratory experiments, earthquakes can occur when one rock surface is rubbed against another. Although researchers can sometimes predict when these simulated earthquakes will occur during controlled experiments, the Earth is much more complicated than any laboratory experiment. Deep fault zones, where actual earthquakes occur, have high temperatures, exotic fluids and even exotic minerals that may make the Earth’s behavior very different from what occurs in laboratory experiments.

Soon, scientists will be able to test their theories with observations at SAFOD. They will observe whether deformations occur before an earthquake happens, whether the deformation can foretell the occurrence of an earthquake, and how large it will be. They will also be able to observe whether fluid pressure changes systematically in earthquakes, and whether these pressure changes play a role in earthquake nucleation. Answers to these questions will help scientists learn much about earthquakes, and lead to improvements in earthquake forecasting.

**Subsurface Maps for SAFOD**

In preparation for SAFOD, an extensive site-characterization study was conducted around the drillsite and across the SAF. A 2.2-km [7,200-ft] deep vertical pilot hole was drilled at the SAFOD site in the summer of 2002. To look at subsurface structure and heterogeneities on multiple scales ranging from hundreds of meters to tens of kilometers, geoscientists relied on studies coordinated by the USGS. These studies, using state-of-the-art technologies and processing techniques, are helping geoscientists understand major geological features and structures in the SAF zone. Some of the results have been surprising.

For example, Paulsson Geophysical Services, Incorporated, a California-based borehole seismic company, developed one of the world’s longest borehole seismic receiver arrays to create a map of the SAFOD subsurface environment. Their 80-level, 4,000-foot [1,219-m], three-component, clamped receiver array was used in two segments in May 2005 for a record-breaking 9,000-foot [2,743-m] long, 160-level, three-channel, detailed VSP of formations surrounding the SAF just before the start of the Phase-2 main borehole drilling.

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10. The initial earthquake phase between the first impulsive arriving P-wave (compressional wave) and the point where the velocity seismogram begins a sudden linear velocity increase is called the nucleation phase. Concepts of the nucleation phase and the fracturing mechanisms are not well understood or universally accepted by all researchers.


After the VSP was completed, the high-frequency (up to 400 Hz), high-sensitivity array was left in the hole for two weeks, recording over 1,000 small and 100 larger (up to magnitude 2.7) earthquakes. These recordings provided seismologists with a surprising discovery: the first observation of nonvolcanic tremors in the SAF (above). Scientists believe that these tremors were caused by deep, repeated slipping events similar to those observed in the Cascadia subduction zone beneath Vancouver Island in British Columbia, Canada.

In another experiment, Duke University recorded VSP surveys in 2003 using a 32-level, three-component, vertical array located in the pilot hole. The large source charges used in the joint GFZ-VPI crustal-profiling survey provided good signals for recording VSP data. Results of the compressional, or P-wave, and shear, or S-wave, velocity analysis indicate significant differences in maximum velocities for inline and crossline transverse components (below). These differences are thought to be caused by vertical

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**Figures and Images:**

- **Observation of nonvolcanic tremors at SAF.** After an 80-level, 4,000-ft, three-component, clamped receiver array (left) was used to produce a 9,000-ft vertical seismic profile at SAFOD, scientists were surprised by the discovery of nonvolcanic tremors (middle), which are believed to be caused by deep slipping events in the Earth. Earthquake seismic profiles are shown (right) for comparison. The tremor seismogram shows long-lasting, oscillating positive (red) and negative (blue) amplitude excursions, while the earthquake seismic energy is concentrated in a relatively short time interval. (Courtesy of William Ellsworth, US Geological Survey.)

- **Velocity semblance plots from a vertical seismic profile at SAFOD (left).** Differences in the maximum velocities for the inline (upper curve) and crossline (lower curve) transverse components were used to determine vertical, parallel fracture orientations (blue line in map on right) in the geologic structure that were aligned approximately 12° from the surface trend expression of the SAF and 7° from the main GFZ-VPI acquisition line (brown line in map).
fractures in the subsurface geologic structure lying approximately parallel with the surface trend of the SAF. These results indicate a complex fracture structure at the SAF, which was later confirmed by analysis of well-logging imaging data obtained in the main borehole.

In 2004, Duke University, in collaboration with Schlumberger, validated the complexity of the SAF with detailed images of faults at greater depths than USGS surface seismic surveys could provide. The Schlumberger Drill-Bit Seismic VSP with drillbit source system was used while drilling the Phase-1 main hole. The seismic dataset was obtained using drillbit energy as a low-cost, high-amplitude seismic source. This produced a real-time inverse VSP from the signals generated by the drill bit, giving geoscientists a chance to look ahead of the bit for reflections caused by the faults and for changes in lithology expected at SAFOD (right).

Schlumberger donated the instruments used for the Drill-Bit Seismic VSP. These included accelerometers mounted on the topdrive of the drilling rig used for recording the drillbit signal, along with geophones and cabling for installing a 46-channel geophone array on the surface. The surface geophone array extended along a line directed away from the drilling location, toward the SAF. Schlumberger scientists used a velocity profile map produced from a tomographic inversion of the previous summer’s VSP-measured P-wave traveltimes, using 47 shots from the GFZ-VPI crustal profiling survey (right).

This profile enabled drillbit-seismic data processing to identify potential changes in geology or subsurface conditions and convert measurements of reflection times into an image of the formation surrounding the borehole, a process called wavefield migration. SeisDB software for managing seismic data, provided by Schlumberger, was used to oversee the data acquisition and quality control. The primary data processing required proprietary adaptive filtering, correlation, digital array filtering with adaptive beam-forming techniques and multichannel deconvolution. Additional processing techniques included notch filtering for electrical noise and bandpass filtering of the output wavefield.

Migrating the reflected wavefield produced a clear image of the subsurface around the SAFOD Phase-1 deviated wellbore that correlates well with locations and dips of many linear features and faults imaged at shallow depths in the 2002

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Both the shallow Tertiary sedimentary cover and underlying Salinian granite block are cut by a complex series of steeply dipping faults. Drill-bit-seismic studies were important because they produced sharp images of the fault zones and helped geologists correlate mineral changes and petrophysical properties seen in well logs with the many seismically observed fault structures (left).

Drill-Bit Seismic imaging also aided drilling engineers in improving their ability to “see into the earth” and drill boreholes and cores cost-effectively, accurately and safely on target. Drilling and sample data confirmed that the borehole intersected several fracture zones during the drilling process. Well logs, discussed later, also confirmed numerous fractures and pinpointed locations where several shear zones were penetrated.

Shear-Wave Velocity Anisotropy

Utilizing shear-wave velocity data, SAFOD scientists were able to address a number of questions related to the origin of shear velocity anisotropy. It is well-known that shear waves traveling through a formation can “split” into fast and slow velocity components in a process known as shear-wave anisotropy. At the SAFOD site, researchers were able to investigate, at a variety of scales, the roles that tectonic stress, preexisting fractures, faults and bedding planes play in shear-wave velocity anisotropy. Shear-wave anisotropy can be studied using three-component seismometers deployed in a borehole, or using logging tools such as the Schlumberger DSI Dipole Shear Sonic Imager tool and Sonic Scanner acoustic scanning platform. These instruments can determine the magnitude of shear-wave anisotropy, or a percent difference between the fastest and slowest velocity components, as well as the direction of the fastest and slowest components.

Stress-induced shear-wave anisotropy occurs in finely laminated shale-sand sequences where clay minerals or grains align along parallel bedding planes or where parallel fractures make a rock more compliant in one direction than in another. In the case of bedding planes and parallel fractures, it is obvious that the rock is more compliant in a direction perpendicular to the planes than parallel to them.

Shear-wave velocity anisotropy can also be observed in a randomly fractured crust, when the stress-induced closure of fractures has a preferential direction, such as the highly...
fractured Salinian granite that surrounds the vertical pilot hole. In fact, in the highly fractured granite encountered by the 2.2-km deep SAFOD pilot hole drilled in 2002, there was an excellent correlation between the “fast” direction of anisotropy and the direction of maximum horizontal stress indicated by wellbore breakouts and drilling-induced tensile fractures.  

In addition to studying shear velocity anisotropy with logging tools in the pilot hole and main hole, a 32-level, three-component seismometer array was installed in the pilot hole. This array was used to study shear velocity anisotropy with waves coming from nine local micro-earthquakes. They occurred over a two-year period from 2002 to 2004 in the SAF, about 1.5 km [4,920 ft] away from the SAFOD pilot hole, at a depth between 2.7 km [8,860 ft] and 7.3 km [23,950 ft] (previous page, bottom).

Scientists observed that receivers in the upper portion of the pilot-hole array consistently showed different results from receivers in the lower half of the array. The upper receivers demonstrate that the nine earthquakes’ shear waves are polarized by stress-induced anisotropy—the polarization direction of the fastest velocity components were aligned in a north-northeast direction parallel to the direction of the maximum horizontal formation stress observed in borehole breakout measurements. They also showed that the polarization magnitude decreased with depth, as expected—due to increasing confining stress that closed the fractures. However, the lower-array receiver results indicate that the earthquake shear waves appeared to be polarized by structural anisotropy.

The observed fast polarization direction was aligned with the fabric of bedding planes—not in the direction of the maximum horizontal stress, and anisotropy magnitude increased with depth, which is inconsistent with stress-induced anisotropy. Initially, it was not clear to SAFOD researchers how each of these earthquakes could generate both stress-induced anisotropy and structural anisotropy at different receivers in the same vertical array.

The mystery was solved with information from FMI Fullbore Formation MicroImager borehole imaging and other petrophysical logs. Scientists discovered layered sediments, dipping in a southwest direction, and perpendicular to the deviated main borehole. Seismic waves from the earthquakes to the lower pilot-hole array seismometer receivers apparently traveled through the dipping sediment’s bedding planes, which explains the structural-induced shear-wave anisotropy observed on the lower receivers. Though well logs do not indicate how deep the sediments extend, they may extend far enough downward that the lower rays paths travel entirely through the sediments. It is known that the anisotropy effects are cumulative along the raypath, and the observed shear-wave polarization direction seen in the seismometer is controlled by the last anisotropic medium encountered by the wave. Thus, the bedding polarizes the lower rays, whose paths travel through the sediments immediately before entering the lower receivers. In contrast, although the seismic rays traveling from the earthquakes to the upper array receivers probably go through a significant portion of the sedimentary layers, the last part of their path is through fractured Salinian granite lying above the sedimentary section, giving rise to the observed apparent stress-induced shear-wave anisotropy.

Finding Faults

In addition to seismic maps, SAFOD scientists are learning to use other new seismic techniques to map the complex fault structure associated with the SAF system. For example, researchers observed that seismic waves from earthquakes could become trapped in a fault zone. Often, when an earthquake occurs inside or very near a fault zone, the seismic waves are bent along the fault and eventually propagate within the core of the fault—trapped in the fault like microwaves in a microwave oven. The wavelengths of the trapped waves are controlled by the dimensions and low velocity of the 100-m [330-ft] to 250-m [820-ft] thick damaged zone of the fault (above). The signal on a seismometer placed somewhere in the fault zone or on the surface near the fault will be large, but it decreases quickly as the seismometer is moved away from the fault, as though the seismic energy is trapped inside the fault itself.

This kind of seismic wave is called “guided” because the seismic waves can have large amplitudes and will propagate over great distances along a given fault. However, the fault-zone guided waves need a continuous fault to remain trapped. This makes them good indicators of uniform faults composed of one segment. These waves are also useful for mapping the spatial extent, width and continuity, or the stratigraphy, of the fault zones, and for finding out which faults are connected to the earthquake site.

SAFOD researchers use another interesting strategy to find earthquakes deep in the subsurface. After drilling a segment of borehole, they stop and set up seismometers downhole to observe earthquake shock waves. Then, using checkshots or logging data, they refine their velocity information to compute a more precise earthquake location.

For example, in May 2005, just before Phase-2 drilling began, scientists using the Paulsson array in the Phase-1 borehole observed a magnitude 0 earthquake directly ahead along the planned Phase-2 borehole trajectory. Using sonic velocities from LWD logs, they combined logging and seismic information to locate the exact position along the borehole where this earthquake occurred. Its position coincided with an anomalously low sonic-velocity layer seen in the logs, validating their earthquake-finding approach. Thus, the scientists saw that the extensive damage zone associated with the SAF contains more than one active fault core: one generates earthquakes and the other is creeping. The sharp velocity drops are “signatures” of the active faults. In 2007, scientists will cut whole-core samples in these zones during Phase-3 drilling to learn more about the active fault areas.

Journey to the Center of an Earthquake
Between the end of Phase 2, completed last summer, and Phase-3 drilling, which begins in 2007, scientists have two years to study the data from the first two phases of logging and seismic measurements. They will also be able to monitor processes in the borehole to study the ongoing SAF deformation and refine the locations of earthquake patches.

The big question at the end of Phase-2 drilling was this: where along the borehole is the SAF moving? After a magnitude 6 earthquake at Parkfield in 2004, global positioning system measurements were used to generate surface maps of the area; these maps indicate that the overall creep rate has sped up. As a fault slips, it transfers stress, causing the creep rate to increase and then decrease back to normal rates as the earthquake transient dissipates.

Openhole LWD logs show narrow beds with anomalous drops in sonic compressional and shear velocities, $V_p$ and $V_s$, respectively, which correlate with low resistivities and high neutron porosities in the lower borehole over a 200-m [656-ft] wide region. These characteristics indicate that extensively damaged zones surround a number of potential fault candidates. After casing was set, a Schlumberger 40-arm caliper log was run and periodic relogging showed researchers that the casing is deforming at several narrow 1- to 3-m [3- to 10-ft] zones, correlating with anomalously low acoustic velocities seen in petrophysical logs (above).

These results help scientists identify the exact location where the SAF is creeping. They are currently studying how shear strain is accumulating while they look for other zones where deformation might occur.

Unraveling the Fabric of the Fault Zone
By separating stress-induced and structural anisotropy, researchers have been able to supplement existing stress data regarding the crust surrounding the SAF in Parkfield. Past polarization directions in the sonic logs indicate that the maximum horizontal stress rotates clockwise (north to northeast) from 0° near the surface to 45° within a few hundred meters of the

^The core of the fault. A high vertical- and radial-resolution 40-arm caliper tool measured continually increasing casing deformation where the well crossed the SAF (inset). This deformation correlates with anomalous drops observed in acoustic velocities seen in openhole LWD logs.

23. The gradual accumulation and release of stress and strain is now referred to as the “elastic rebound theory” of earthquakes developed by Henry Fielding Reid, Professor of Geology at The Johns Hopkins University, who concluded that earthquakes involve an “elastic rebound” of previously stored elastic stress. For more on Reid’s elastic rebound theory: http://quake.wr.usgs.gov/info/1906/reid.html (accessed May 3, 2006).
active fault plane. This observation supports the interpretation that the maximum horizontal stress is nearly perpendicular to the strike of the SAF at a vertical depth of 2,500 m [8,200 ft]. That interpretation further implies that the SAF is a weak fault that slips at low levels of shear stress.

Observation of shear-wave anisotropy with sonic logging and seismic instruments illustrates the effects of measurement scale on frequency, wavelength and structure. Seismic waves with wavelengths of 30 km [18.6 miles] will be polarized only if the smallest wavelength is larger than the individual layer thickness. By contrast, sonic waves from a logging tool typically have wavelengths of one meter or so, and thus are polarized by sedimentary bedding in finely laminated shale zones with closely spaced bedding planes. By exploiting the differences between seismic and sonic measurement scales, geophysicists are learning more about earthquake propagation, as well as subsurface stress-strain orientations.

Theories to explain the weakness of the SAF are abundant in the literature and include frictionally weak materials in the fault core, high pore pressure that reduces the normal stress, and dynamically weakening mechanisms. The significance of each theory can be determined only when direct measurements of the state of stress, porosity, permeability, fluid pressures, deformation, and other key properties and processes are determined.

Preliminary analysis of the Phase-2 petrophysical logs provided an interesting surprise. The logs show that the $V_p/V_s$ ratio does not change significantly in the core of the SAF or throughout the extended damaged zone. This result implies that the SAF does not have high fluid pressure, which was a significant requirement for one of the theories concerning earthquake nucleation.

**An Earthshaking Future**

By the time Phase-3 drilling begins in 2007, seismologists expect to know precisely where the majority of magnitude 2 earthquakes and deformations are occurring at SAFOD. Multilateral boreholes will be sidetracked from the main borehole into these active fault patches, and from them whole cores and samples will be taken to study why each section is moving (above right).

Some faults are creeping and others are creating earthquakes. By placing multilaterals in each type of fault, researchers plan to perform classic science experiments comparing earthquake-producing faults with control faults—creeping faults. Arrays of state-of-the-art, three-component seismometers using solid-state accelerometers as well as traditional moving-coil geophones along with tiltmeters will be stretched across each fault zone, monitoring when and where earthquakes occur. This information, combined with differences in microstructure, mineralogy and deformation between fault groups will soon yield a more complete picture of fault behavior.

Researchers are excited about the chance to work across so many different disciplines of geosciences and engineering. They are combining field research and laboratory experimentation to understand what is happening deep in earthquake-producing faults. This research is helping scientists determine whether earthquakes can be forecasted, and if so, how?

By participating in these borehole observatory studies and working with a wide range of academic and other geoscience researchers from outside the E&P community, Schlumberger scientists and engineers can field-test developing technologies, such as the Drill-Bit Seismic system. The ability to collaborate and openly share data on the SAFOD project is a worthwhile benefit. An important, mutual benefit is that the EarthScope and SAFOD projects are helping to train a new generation of earth scientists who may eventually work in the oil and gas industry. More important, though, are the benefits derived from improved understanding of the processes that affect earthquake nucleation. —RH, MV
Highlighting Heavy Oil

Dwindling oil supply, high energy prices and the need to replenish reserves are encouraging oil companies to invest in heavy-oil reservoirs. Heavy and viscous oils present challenges in fluid analysis and obstacles to recovery that are being surmounted by new technology and modifications of methods developed for conventional oils.
Most of the world’s oil resources are heavy, viscous hydrocarbons that are difficult and costly to produce and refine. As a general rule, the heavier, or denser, the crude oil, the lower its economic value. Less dense, lighter ends of crude oil derived from simple refining distillation are the most valuable. Heavy crude oils tend to have higher concentrations of metals and other elements, requiring more effort and expense to extract usable products and dispose of waste.

With high oil demand and prices, and production of most conventional-oil reservoirs in decline, industry focus in many parts of the world is shifting to exploitation of heavy oil. Heavy oil is defined as having 22.3°API or less. Oils of 10°API or less are known as extraheavy, ultralight or superheavy because they are denser than water. In comparison, conventional oils such as Brent or West Texas Intermediate, have densities from 38° to 40°API.

While oil density is important for evaluating resource value and estimating refining output and costs, the fluid property that most affects producibility and recovery is oil viscosity. The more viscous the oil, the more difficult it is to produce. There is no standard relationship between density and viscosity, but “heavy” and “viscous” tend to be used interchangeably to describe heavy oils, because heavy oils tend to be more viscous than conventional oils. Conventional-oil viscosity may range from 1 centipoise (cP) [0.001 Pa.s], the viscosity of water, to about 10 cP [0.01 Pa.s]. Viscosity of heavy and extraheavy oils may range from less than 20 cP [0.02 Pa.s] to more than 1,000,000 cP [1,000 Pa.s]. The most viscous hydrocarbon, bitumen, is a solid at room temperature, and softens readily when heated.

Since heavy oil is less valuable, more difficult to produce and more difficult to refine than conventional oils, the question arises as to why oil companies are interested in devoting resources to extract it. The first part of the two-part answer is that under today’s economic conditions, many heavy-oil reservoirs can now be exploited profitably. The second part of the answer is that these resources are abundant. The world’s total oil resources amount to roughly 9 to 13 trillion barrels [1.4 to 2.1 trillion m³]. Conventional oil makes up only about 30% of that amount, with the remainder in heavy oil, extraheavy oil and bitumen (top right).

**Formation of Vast Resources**

Of the world’s 6 to 9 trillion barrels [0.9 to 1.4 trillion m³] of heavy and extraheavy oil and bitumen, the largest accumulations occur in similar geological settings. These are supergiant, shallow deposits trapped on the flanks of foreland basins. Foreland basins are huge depressions formed by downwarping of the Earth's crust during mountain building. Marine sediments in the basin become source rock for hydrocarbons (dark brown) that migrate updip into sediments (orange) eroded from the newly built mountains. Microbes in these sediments often lack sealing caprocks. In these shallow, cool sediments, the hydrocarbon is biodegraded.
Biodegradation is the main cause of the formation of heavy oil. Over geologic time scales, microorganisms degrade light and medium hydrocarbons, producing methane and enriched heavy hydrocarbons. The effect of biodegradation is to cause oxidation of oil, decreasing gas/oil ratio (GOR) and increasing density, acidity, viscosity and sulfur and other metal content. Through biodegradation, oils also lose a significant fraction of their original mass. Other mechanisms, such as water washing and phase fractionation, contribute to the formation of heavy oil, separating light ends from heavy oil by physical rather than biological means. Optimal conditions for microbial degradation of hydrocarbons occur in petroleum reservoirs at temperatures less than 80°C [176°F]; the process is therefore restricted to shallow reservoirs, down to about 4 km [2.5 miles].

The largest known individual petroleum accumulation is the Orinoco heavy-oil belt in Venezuela with 1.2 trillion barrels [190 billion m³] of extraheavy, 6 to 12°API oil. The combined extraheavy oil accumulations in the western Canada basin in Alberta total 1.7 trillion bbl [270 billion m³]. The sources of these oils are not completely understood, but it is agreed in both cases that they derive from severely biodegraded marine oils. The 5.3 trillion barrels [842 billion m³] in all the deposits of western Canada and eastern Venezuela represent the degraded remains of what was probably once 18 trillion barrels [2.9 trillion m³] of lighter oils. In any depositional environment, the right combination of water, temperature and microbes can cause degradation and formation of heavy oil. Tar mats occur in many reservoirs near the oil/water contact, where conditions are conducive to microbial activity. The depositional environment, the original oil composition, the degree to which it has been degraded, the influx of, or charging with, lighter oils and the final pressure and temperature conditions make every heavy-oil reservoir unique, and all of them require different methods of recovery.

### Recovery Methods

Heavy-oil recovery methods are divided into two main types according to temperature. This is because the key fluid property, viscosity, is highly temperature-dependent; when warmed, heavy oils become less viscous (left). Cold production methods—those that do not require addition of heat—can be used when heavy-oil viscosity at reservoir conditions is low enough to allow the oil to flow at economic rates. Thermally assisted methods are used when the oil must be heated before it will flow.

The original cold method of heavy-oil recovery is mining. Most heavy-oil mining occurs in open-pit mines in Canada, but heavy oil has also been recovered by subsurface mining in Russia. The open-pit method is practical only in Canada where the surface access and volume of the shallow oil/sand deposits—estimated at 28 billion m³ [176 billion barrels]—make it economic.

Canadian oil sands are recovered by truck and shovel operations, then transported to processing plants where warm water separates bitumen from sand (right). The bitumen is diluted with lighter hydrocarbons and upgraded to form synthetic crude oil. After mining, the land is refilled and reclaimed. An advantage of the method is that it recovers about 80% of the hydrocarbon. However, only approximately 20% of the reserves, or those down to about 75 m [246 ft], can be accessed from the surface. In 2005, Canadian bitumen production was 175,000 m³/d [1.1 million bbl/d]. This is expected to grow to 472,000 m³/d [3 million bbl/d] by 2015.

Some heavy oils can be produced from boreholes by primary cold production. Much of the oil in the Orinoco heavy-oil belt in Venezuela is currently being recovered by cold production, as are reservoirs offshore Brazil. Horizontal and multilateral wells are drilled to contact as much of the reservoir as possible. Diluents, such as naphtha, are injected to decrease fluid viscosity, and artificial lift technology, such as electrical submersible pumps (ESPs) and progressing cavity pumps (PCPs) lift the hydrocarbons to the surface for transport to an upgrader. An advantage of the method is lower capital cost.
expenditure relative to thermally assisted techniques, but the recovery factor is also low—6 to 12%. An additional challenge is the increase in fluid viscosity that arises with the formation of oil-water emulsions, caused by mixing and shearing in pumps and tubulars.

Cold heavy-oil production with sand (CHOPS) is another primary production method that has applicability in many heavy-oil reservoirs. In hundreds of fields in Canada, sand—up to 10% “sand cut” by volume—is produced along with the oil (right). Gas exsolving from the depressurized oil helps destabilize and move sand grains. Sand movement increases fluid mobility and forms channels, called wormholes, which create a growing zone of high permeability around the well. The overburden weight helps extrude sand and liquids. Sand and oil are separated by gravity at surface, and the sand is disposed of into permeable strata. The method requires multiphase pumps that can handle sand, oil, water and gas, and has been applied in reservoirs with oil viscosity from 50 to 15,000 cP [0.05 to 15 Pa.s]. In Canada, annual production of heavy oil by the CHOPS method was 700,000 bbl/d [111,230 m³/d] as of 2003.

Waterflooding is a cold enhanced oil-recovery (EOR) method that has been successful in some heavy-oil fields. For example, offshore fields on the UK continental shelf use waterflooding to produce 10- to 100-cP oil from long, screen-supported horizontal wells to a floating production, storage and offloading (FPSO) system. The method is being considered for nearby fields with higher viscosity fluids, but the recovery factor decreases with increasing oil viscosity. High-viscosity oils cause viscous fingering in waterflood fronts, resulting in poor sweep efficiency.

Vapor-assisted petroleum extraction (VAPEX) is a relatively new process being tested in Canada. It involves the injection of a miscible solvent, which reduces the viscosity of heavy oil. The method can be applied one well at a time or in well pairs. In the single-well approach, the solvent is injected from the toe of a horizontal well. In the double-well case, solvent is injected into the upper well of a pair of parallel horizontal wells. Valuable gases are scavenged after the process by inert gas injection. VAPEX has been studied extensively in the laboratory and in simulations, and is undergoing pilot testing, but has not yet been deployed in large-scale field operations.

Thermal methods, like their cold counterparts, have advantages and limitations. Recovery factors are higher than for cold production methods—with the exception of mining—but so are costs associated with heat generation and water treatment. Cyclic steam stimulation (CSS), also known as steam soak, or
Steam-assisted gravity drainage (SAGD) works for extraheavy oils. A pair of parallel horizontal wells is drilled, one well about 5 to 7 m [16 to 23 ft] above the other (next page, top). Steam injected into the upper well heats the heavy oil, reducing its viscosity. Gravity causes the mobilized oil to flow down toward the lower horizontal producer. Initial communication is established between the injector and producer by steam, cyclic steam or solvent injection. The estimated recovery factor for this method is between 50 and 70%. However, formation layering can significantly influence SAGD recovery. SAGD is used in many fields in Canada, including Christina Lake and MacKay River.

In-situ combustion, also known as fireflooding, is a method for mobilizing highly viscous oils. It is a multiwell process in which a combustion front initiated at an air-injection well propagates to a producing well. The in-situ combustion burns some of the oil, and the heat sufficiently reduces the viscosity of the rest to allow production. The burnt oil, or combustion residue, is left behind. The combustion upgrades the crude oil by cracking, or separating small molecules from large ones. Most attempts at field application have found the process to be unstable. However, in Romania, the large-scale fireflooding operation in the Suplacu de Barcău field has been operating since 1964. New technologies are being developed to stabilize the combustion front in the in-situ combustion process. For example, the THAI Toe-to-Heel Air Injection method, a trademark of Archon Technologies Ltd., uses a combination of vertical injector and horizontal producer. The method is currently in field pilot test in the McMurray formation near Conklin, Alberta.15

Selecting a Recovery Method

With various recovery methods available, selecting the best one for a particular reservoir requires a comprehensive study that incorporates many factors, such as fluid properties, formation continuity, rock mechanics, drilling technology, completion options, production simulation and surface facilities. This multidisciplinary team effort must also consider trade-offs between factors such as reserves, expected recovery rates and production rates. Also required is consideration of the cost of energy generation and the environmental sensitivity of the surroundings. An example of the type of screening study that can help companies decide how to produce heavy-oil resources comes from the North Slope in Alaska, where BP Exploration (Alaska) Inc. is assessing methods for producing the high-viscosity oil in the Ugnu sands (next page, bottom).

The Ugnu sands and their deeper neighbor, the Schrader Bluff formation, were first encountered in 1969, when operators drilled and tested the deeper Kuparuk formation. At the time, there was no viable technology to develop the highly viscous oils in the Ugnu and Schrader Bluff sands, so the companies concentrated on the prolific Kuparuk formation. The Schrader Bluff formation is a stratigraphically deeper formation and contains relatively lighter viscous oil than the Ugnu. Sections of the Schrader Bluff formation are on waterflood and have been producing since the early 1990s. Over the years, several companies conducted simulations and pilot studies to assess the feasibility of waterflooding and other enhanced oil-recovery (EOR) methods for producing the Ugnu, but failed to find economic means to exploit the heavy-oil resources.16
BP is currently evaluating development of the heavy-oil reserves in the Milne Point unit of the North Slope. The total prize is estimated to be billions of barrels of oil originally in place in the Lower Ugnu formation, with a significant percentage positioned in BP’s Milne Point unit. The reservoir and fluid properties vary across the field, and are generally represented by high oil density and viscosity and a low reservoir temperature of 75°F [24°C]. This means the reservoir clearly requires nonprimary recovery methods such as some form of enhanced cold production, cyclic steam stimulation, steamflooding, SAGD or hybrid process.

To determine the best approach, a 30-member team comprising BP and Schlumberger specialists conducted a screening study. The objective of the study was to identify the development technique that would economically maximize oil production rates and recovery factor, while ensuring minimal and acceptable heat loss to permafrost and minimal effect on naturally occurring gas hydrates. The screening study emphasized CO₂ and greenhouse-gas handling and usage, and enforced the highest standards of HSE. A joint BP/Schlumberger technology study is currently under way to examine options to bring heavy-oil developments in line with BP’s Green Agenda. The study results will be input to the BP Appraise Stage Plan for final decision making on Ugnu development.

The screening study reviewed previous studies and reports issued during the last 25 years. With these studies and available data,
three representative wells in the Milne Point area were selected for a detailed review. The wells penetrated intervals of varying reservoir quality. To determine the best recovery method, several were simulated, including steamflooding, CSS, SAGD, hot waterflooding and primary production. The effects of vertical, deviated and horizontal wells were also tested in the simulation runs.

The results of the study were compiled in an interactive matrix that quantified the sensitivity of each recovery method to production, subsurface, surface and cost factors. Each matrix block was colored according to factor sensitivity to performance or knowledge importance. In terms of performance, green means excellent, yellow means fair and red means poor. In terms of knowledge importance, green means less important, yellow means important and red means critical. For example, in the production categories, CSS was rated excellent performance for production rate per well, reserves per well and reserves recovery. Of the subsurface factors, for example, fluid characterization and rock-mechanical properties are rated critical knowledge importance for every EOR method assessed. In the interactive version of the matrix, clicking on a box accesses the reports and studies behind the evaluation.

Reservoir fluid PVT properties, in particular fluid viscosity and its variation with temperature, are crucial factors in selection of a recovery technique. These were inadequately known for the fluids in the Ugnu formation. Measured oil-viscosity data were limited to two production samples with dead-oil viscosities of 200 and 2,500 cP at 80°F [0.2 Pa.s and 2.5 Pa.s at 27°C]. These samples are not thought to be representative of the entire range of viscosities present in the Ugnu sands. Geochemical transforms were used to predict oil viscosity from sideway core samples. However, this technique relied on extrapolation beyond the range of measured viscosities and made the assumption that Ugnu oils have the same controls on oil quality as the Schrader Bluff oils. Although the model served as a good starting point, fine-tuning this model for predicting oil viscosity and collection of additional samples was one of the recommendations made in the study.

Another critical factor, rock-mechanical properties, was assessed by examination of core and analysis of DSI Dipole Shear Sonic Imager logs from the MPS-15 well. Ugnu sand has extremely low strength, less than 200 psi [1.4 MPa] in estimated unconfined compressive strength; the core is soil-like and easily crushed by hand, foreshadowing potential wellbore-stability and completion challenges. Additionally, two distinct peaks were noted on the sand size distribution. These indicate that a considerable amount of silt, 5- to 60-micron sized, may be produced along with fine- to very-fine-grain sand of 60 to 250 microns. These fines will have to be either controlled or managed with Ugnu oil production.

To determine suitable drawdown pressures and a depth-stability envelope for production, estimates of mechanical-property data and completion options, such as perforation size and orientation, were input to the Sand Management Advisor software. These initial calculations...
determined that any drawdown greater than 1 psi [6.9 kPa] would cause complete sand failure. The recommendation was to anticipate sand production during drilling and completion, and to develop creative sand-management strategies, such as microslotted liners.

Of the five recovery methods assessed, cyclic steam stimulation gave the best recovery and production rates. If this method is selected, care will have to be taken not to overheat the permafrost. This should be possible since the reservoir is isolated from permafrost layers by a thick, impermeable shale. Other methods, such as primary cold production, would have minimal impact on permafrost, but may have difficulty yielding economic recovery or production rates. SAGD, while having a similar environmental impact as CSS, would not be as effective in the study location, because it requires a high ratio of vertical to horizontal permeability for development of a steam chamber. Continuity of the Ugnu formation will significantly influence the final recovery factor, and reservoir description will be a critical component of ongoing work.

Ultimately, the screening study recommended cyclic steam stimulation as the optimal recovery method for the area of study in the Milne Point unit, and outlined well spacing, orientation and patterns. Also, additional simulation was recommended to assess the effects of varying steam-injection rates and volumes and to investigate the feasibility of converting to steamflooding.

Characterizing Heavy Oils Downhole
A critical step in determining the best heavy-oil recovery method is to characterize reservoir fluid properties. For the purposes of grading reserves and selecting sampling intervals, companies turn to downhole measurements of fluid properties, especially viscosity.

Knowledge of viscosity throughout the reservoir is vital for modeling production and predicting reserves recovery. However, heavy-oil viscosity can exhibit large variations, even within the same formation. Building a viscosity map requires adequate sampling and logging-derived information of in-situ viscosity.

Nuclear magnetic resonance (NMR) logging has been used successfully to determine in-situ viscosity of conventional oils, but current commercial methods have limitations in heavy and viscous oils. This is because as fluid viscosity increases, NMR relaxation time, \( T_2 \), decreases. When relaxation times are extremely short, NMR logging tools cannot detect them.

When viscosity is greater than about 100,000 cP [100 Pa.s], NMR tools see most of the heavy oil or bitumen as part of the rock matrix.

To improve understanding of the correlation between viscosity and NMR response, researchers at the University of Calgary and its affiliate institute, the Tomographic Imaging and Porous Media (TIPM) Laboratory, acquired and interpreted laboratory NMR measurements on a large selection of Canadian heavy oils. Oils in the database have viscosities ranging from less than 1 cP to 3,000,000 cP [0.001 to 3,000 Pa.s].

Measured viscosities showed a correlation with two NMR parameters, but with differing sensitivities. With increasing viscosity, \( T_2 \) decreased and, at high viscosities, became less sensitive to changes in viscosity. However, increasing viscosity caused the decreasing relative hydrogen index (RHI) to become more sensitive to viscosity change at high viscosities (above).

On the basis of these findings, the researchers developed a new empirical relationship between the NMR parameters and fluid viscosity. The relationship was adjusted to provide the best possible fit for the five oils in the database for which viscosity data were available over a range of temperatures (below).

Translating this laboratory NMR-viscosity relationship to one that works for NMR logging tools is not straightforward. Heavy oils in rocks are mixed with other fluids and exhibit behaviors that differ from bulk fluids in the laboratory. However, the right combination of laboratory and logging measurements can provide the information necessary to fine-tune the viscosity relationship and produce a continuous viscosity...
A continuous oil-viscosity log produced from Platform Express data and CMR-200 measurements, calibrated to laboratory oil-viscosity values. From X64 to X80 m, the continuous viscosity log (Track 5) shows a viscosity gradient, with oil viscosity increasing from 30,000 to 300,000 cP.

In this heavy-oil example from Western Canada, data from the Platform Express integrated wireline logging tool and CMR-200 Combinable Magnetic Resonance measurements were used to produce an oil-viscosity log that showed good agreement with laboratory oil-viscosity measurements in a range from 30,000 to 300,000 cP [30 to 300 Pa.s].

Viscosity measurements in this well show not only variation, but also a gradient of increasing viscosity with depth in the interval from X64 to X80 m. While this type of gradient is common in this area, other regions show the opposite effect.
with viscosity decreasing with depth. The ability to estimate heavy-oil viscosity will help companies map viscosity changes throughout their heavy-oil reservoirs and ultimately aid in determining the appropriate completion and recovery strategies.

**Sampling Heavy, High-Viscosity Fluids**

Evaluating the productivity potential of heavy-oil reservoirs has been difficult because high fluid viscosity and unconsolidated formations make it difficult to acquire representative fluid samples and test reservoir dynamics (right). There is no unique solution to the problem of collecting heavy-oil samples in unconsolidated sands, but best practices and sampling techniques developed for the MDT Modular Formation Dynamics Tester are allowing improved characterization of many heavy-oil reservoirs.

Some of the new technology includes an extra-large-diameter probe, a focused probe, dual packers with customized gravel-pack screens, an extra-high-pressure displacement pump for low flow rates, advanced downhole fluid analysis and specialized sampling methodology.

A methodology that has successfully collected samples of high-viscosity oil starts by simulating the multiphase flow around the wellbore to model the decrease in drilling-fluid contamination with time as fluid is pumped into the wellbore. By varying oil viscosity, permeability anisotropy, drilling-fluid invasion, flow rate and MDT position, it is possible to estimate the pumping time required to collect a sample of sufficiently low contamination. The cleanup time is highly dependent on the effective radius of invasion. Fortunately, oil of extremely high viscosity restricts invasion, reducing the volume of fluid that needs to be pumped before uncontaminated fluid is pulled into the tool flowline. In one case in South America, a technique using the MDT dual-packer module and a flow rate less than 1 cm$^3$/s successfully sampled oil of viscosity greater than 3,200 cP [3.2 Pa.s] (right).

In another case, exploring in the northwest state of Rajasthan, India, Cairn Energy discovered the Bhagyam field in 2004. The Bhagyam field is one of 17 fields in the Barmer basin, and produces from the high-permeability Fatehgarh sandstone. Oil reserves in the basin are currently estimated at 650 million bbl [103 million m$^3$].

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Crude-oil properties vary widely in the basin, from 15°API in the north to 52°API farther south (above). In the Bhagyam field, oil density ranges from 21°API at the bottom to 30°API at the top. Although they are not as dense as other heavy oils, Bhagyam oils have high wax and asphaltene content, giving them high pour point and high viscosity at reservoir temperature.

Acquiring representative, PVT-quality samples of these viscous oils has been a challenge. Reservoir sections are drilled with oil-base mud (OBM) to avoid shale collapse. During sample collection, OBM filtrate is collected along with reservoir fluid, contaminating the oil sample. Of the more than 30 samples acquired by Schlumberger and another service company using traditional formation testers, all have been deemed nonrepresentative—too contaminated to yield correct PVT properties during laboratory analysis. Filtrate contamination can be assessed downhole by the LFA Live Fluid Analyzer in real time before fluid samples are collected. For example, at one sampling station in the Bhagyam-4, LFA analysis quantified volume-percent contamination at 43% even after 105 minutes of pumping (above).

Using a new sampling module on the MDT tool, it is now possible to achieve zero filtrate contamination. The Quicksilver Probe wireline sampling tool uses a focused sampling approach whereby contaminated fluid is pumped into one flowline, completely isolated from pure reservoir fluid collected in a second sampling flowline. This focused sampling approach was used in two Bhagyam wells with excellent results. In Bhagyam-5, after 27 minutes pumping time, the Quicksilver Probe sampler drew in fluid that registered 0% OBM contamination on the LFA detector. Later, independent laboratory analysis confirmed a contamination level of 0%. In Bhagyam-6, the Quicksilver Probe-LFA combination sampled fluid that averaged 2.2% contamination after 52 minutes of pumping. Subsequent laboratory analysis determined a contamination level of 0%. Of the 18 samples collected from the two wells, 15 were of PVT quality and 6 samples showed zero contamination (next page, top).
Laboratory Analysis of Heavy Oils

Compared with conventional oils, viscous heavy-oil samples not only are more difficult to acquire, they also present several challenges in laboratory fluid analysis. Traditional techniques for analyzing key fluid properties can fail to fully characterize heavy-crude samples. To solve this problem, researchers and engineers at the Schlumberger Reservoir Fluids Center (SRFC) in Edmonton, Alberta, Canada, have developed new methodologies for determining phase and viscosity behavior of heavy oils (bottom right). In addition, compositional analysis techniques currently used on conventional oils have been applied to heavy oils, with a view to understanding the limitations and identifying potential improvements.

Of the several laboratory techniques that have been developed to describe the chemical composition of oils, the most common is gas chromatography (GC). This type of analysis describes the chemical nature of the oil in sufficient detail to capture differences between oils without significantly increasing simulation time. Standard GC analysis can determine chemical composition of a conventional oil up to C36+. Its strength is in detecting the light components of conventional oils. However, standard GC cannot differentiate the high number of large compounds in heavy oils with sufficient detail to use in simulation.

For compositional characterization of heavy oils, SRFC engineers perform additional analysis techniques that more fully examine these high-density, high-viscosity fluids. The techniques include analysis of saturate, aromatic, resin and asphaltene (SARA) fractions and simulated distillation. Each of the techniques has advantages and inherent limitations.

24. Pour point is the minimum temperature at which oil pours or flows.
25. PVT-quality samples are those that have sufficiently low contamination, such that PVT properties measured in the laboratory correspond to those of an uncontaminated sample. The maximum allowable contamination varies by company and laboratory. A common standard is 7% contamination for this basin.
26. In GC, a sample is vaporized, then carried by an inert gas through a column that separates components. Each component produces a separate peak in the detector output.
27. The phrase “composition to C36+” indicates that compounds of up to 35 carbon atoms are separately discriminated, with the remainder combined into a fraction indicated as C36+.
28. Crude oil is a complex mix of components of different molecular structures and properties. Saturates, also known as alkanes or paraffins, are long hydrocarbon chains of the form CnH2n+2. Aromatics incorporate one or more benzene \([C_6H_6]\) rings. Resins are nonvolatile constituents that are soluble in \(n\)-pentane \([C_5H_{12}]\) or \(n\)-heptane \([C_7H_{16}]\). Asphaltenes are nonvolatile constituents that are insoluble in \(n\)-pentane or in \(n\)-heptane.

Laboratory Contamination Analysis

Low contamination levels were achieved in fluid samples acquired with the Quicksilver Probe focused sampling tool. Laboratory analysis corroborated downhole fluid-analysis results. Of the 18 samples collected, 15 were of PVT quality, and 6 of these showed no contamination. The dashed pink line indicates the contamination level, 7%, below which samples are considered to be of PVT quality.

The Schlumberger Reservoir Fluids Center (SRFC), in Edmonton, Alberta. At SRFC, experts carry out both research and engineering activities, focusing on areas of phase behavior, flow assurance, enhanced oil recovery and heavy-oil production.
SARA analysis fractionates stock-tank oil into weight percent saturate, aromatic, resin and asphaltene by solubility and chromatography. Although SARA analysis resolves only four components and seems low-resolution compared with the thousands of components resolvable by GC techniques, the strength of the method is that it analyzes the entire sample, from light to heavy compounds, and so allows all oils to be compared on a consistent standard. For example, SARA analysis confirms the expected increase in resin and asphaltene content with decreasing API gravity (above). In addition, for conventional oils, SARA analysis gives an indication of fluid stability with respect to asphaltene precipitation, an important consideration when designing production schemes and facilities. In the case of heavy oils, SARA analysis is less useful as an indicator of asphaltene precipitation, which typically occurs when the heavy oil is diluted with certain gases or solvents. Also, SARA-analysis practices can vary, making it difficult to compare measurements made at different laboratories.

Simulated distillation is a GC technique that identifies hydrocarbon components in the order of their boiling points. It is used to simulate the time-intensive, true-boiling-point laboratory procedure. When performed at high temperatures, 36 to 750°C [97 to 1,382°F], the technique can resolve components up to C120. The results are valuable for modeling downstream refining processes and can help refiners select crude oils that will produce favorable economic returns. In heavy oils, simulated distillation has limited application, since the larger compounds that make up a significant portion of the heavy oil will undergo chemical degradation at elevated temperatures; cracking begins to occur above 350°C [662°F].

Another important measurement required of an oil sample is its phase behavior, known as PVT behavior. These measurements describe how the properties of an oil are affected by changes in pressure, temperature or composition that may occur during a production process. In the case of heavy oils, new techniques and modifications of existing techniques have been developed to accurately determine heavy-oil fluid properties as functions of pressure, temperature and composition.

Standard laboratory techniques measure PVT properties such as bubblepoint, compressibility, composition, density and gas/oil ratio (GOR). Although it is not precisely a phase property, viscosity also may vary dramatically with pressure, temperature and composition, and so it is included in this set of measurements. For heavy oils, characterizing viscosity behavior is especially important, since even small changes can have large effects on production rates and recoverable oil volumes. In some heavy-oil reservoirs, the apparent viscosity of the oil may change as the oil mixes with gas or water. Gas that evolves from heavy oil during production can form a foam. Mixing heavy oil with water can create an emulsion. The resulting viscosities are markedly different from that of the heavy oil alone.

Some heavy-oil recovery techniques call for injection of steam, gas or viscosity-reducing solvents, such as naphtha, for assisting production or artificial lift. To confirm the viability of these recovery techniques, laboratory measurements quantify the changes in bubblepoint, density, compressibility, composition and number of liquid hydrocarbon phases caused by the addition of gases and solvents. The addition of gases and solvents can further modify heavy-oil properties by causing precipitation of asphaltenes.

To avoid unwanted changes in viscosity and the precipitation of solids, laboratory measurements monitor rheology and solubility changes on live oil with changes in pressure and temperature. Solids screening by titration with potential diluents or injection gases looks for the concentration at which asphaltene precipitation may be induced for a given temperature or pressure.

A fluid property of particular interest in heavy-oil reservoirs is bubblepoint pressure—
the pressure at which dissolved gas comes out of solution. In the laboratory, bubblepoint is
traditionally determined by depressurizing a sample in what is called a constant composition expansion (CCE) test. The bubblepoint is the pressure at which the sample volume increases
significantly. A CCE test that mixes the heavy-oil sample yields a bubblepoint that matches ideal calculations, while the traditional CCE method produces a bubblepoint that is too low.

The traditional CCE method does not give reliable bubblepoint measurements for heavy oils. To obtain the true bubblepoint when the traditional CCE method fails, SRFC analysts use a CCE test designed for heavy oils (above). The true bubblepoint is obtained by allowing time for the gas to separate slowly from the oil and by controlled mixing of the fluid. Performing the test in the short time allowed for conventional oils can result in a bubblepoint that is hundreds of psi lower than the true value.

Similarly, procedures developed for measuring viscosity of conventional oils can lead to large errors when applied to viscous oil. Rheometers or high-pressure capillary viscometers with accurate temperature control are capable of obtaining viscosity values with a measurement error on the order of 5% (above right).

As mentioned earlier, the quality of data depends on obtaining representative samples of the reservoir fluids. In some cases, it is difficult to obtain representative bottomhole and wellhead samples for some of the fluids of interest. Therefore, a procedure was developed to generate recombined heavy-oil samples from liquid samples collected at the surface (above). As with the bubblepoint measurement, recombination must allow time for the gas to diffuse and become fully dissolved in the heavy oil.
To test the effectiveness of the fluid-recombination technique, the fluid derived from the recombination procedure can be tested against wellhead samples for bubblepoint and viscosity. When PVT and viscosity measurements on recombined fluids give comparable results to the wellhead samples, engineers are able to generate an accurate field-specific model for predicting the properties of the heavy oil.

In one case, an oil company was concerned about the presence of emulsified water in some South American live heavy oils.\(^3\) Most heavy oils are produced along with water, whether the water occurs naturally in the reservoir or has been injected in the form of water or steam. During the production process, shear forces stemming from high flow rate through pumps or flow constrictions may be great enough to cause the water to become emulsified in the heavy oil, leading to a rise in viscosity. This, in turn, will affect the efficiency of artificial lift, dramatically increase the energy required to transport the heavy oils and, in some cases, impact the choice of production equipment.

The viscosity and stability of oil-water emulsions depend on water cut and on which phase is continuous. The viscosity of oil-continuous, or water-in-oil, emulsions may increase by more than an order of magnitude over the dry-oil viscosity. The viscosity of a water-in-oil emulsion increases with water cut up to the emulsion inversion point, beyond which the continuous phase changes to water, producing an oil-in-water emulsion. In oil-in-water emulsions, viscosity decreases with water cut.

Characterizing the stability and viscosity of the South American heavy-oil emulsion required development of new experimental techniques at SRFC. Most experimental work on emulsions is performed on stock-tank oil samples. However, live oils contain dissolved gases that may affect the viscosity of the oil and emulsion. SRFC engineers developed a technique to generate emulsions in live oils by recombining stock-tank oil samples with gas to create a live oil. The live oil was then blended with water at various water cuts in a high-pressure, high-temperature (HPHT) shear cell. The shear cell generated emulsions with an average droplet size of 2 to 5 microns. Visual inspection and drop-size analysis confirmed that the live-oil emulsions remained relatively stable up to the inversion point.

The apparent viscosity of the resulting emulsions was measured at two pressures using an HPHT capillary viscometer (top right). The viscosity of the emulsified live heavy oil is clearly higher than the water-free heavy oil, up to five times greater at 50% volume water cut. The lower viscosity at 60% volume water cut indicates an inversion point, where the system converted from a water-in-oil emulsion at or below 50% to an oil-in-water emulsion at 60% volume. The maximum live-oil viscosity in the system occurs, as expected, just prior to the inversion point. Similar to water-free heavy-oil systems, the emulsion viscosity is reduced by an increase in temperature or by an increase in the amount of saturated gas. Clients can use these results to determine pump sizes, estimate the energy required to pump fluids from the reservoir to surface facilities, and design surface separators.

Drillstem testing in heavy-oil reservoirs

To confirm the economic potential of a discovery well, companies perform drillstem tests (DSTs). DSTs provide short-term production to estimate reservoir deliverability, and also to characterize permeability, completion damage and reservoir heterogeneities under dynamic conditions. Drillstem testing typically involves producing a well with a temporary completion, recording pressure, temperature and multiphase flow rates, and acquiring representative fluid samples.

Drillstem testing is especially challenging in reservoirs with high fluid viscosity, low reservoir strength and the presence of emulsions. To
overcome these challenges, Schlumberger engineers devised and implemented a testing scheme that integrates high-resolution pressure and temperature sensors for monitoring fluid phase behavior, ESPs for fluid lifting, multiphase flowmeters for flow-rate measurements and separators for phase separation and sampling. Test efficiency has been enhanced by real-time data transmission, allowing faster and better decision making.

Using this combination of hardware and best practices, Schlumberger engineers have performed DSTs in more than 20 heavy-oil exploration wells offshore Brazil, with successes in extraheavy oil of 9°API and viscosity as high as 4,000 cP [4 Pa.s].

In one case, Devon Energy wanted to characterize a heavy-oil reservoir in the Macaé formation, a loosely consolidated carbonate grainstone in the Campos basin offshore Brazil. The Macaé formation was a potential candidate for acid stimulation, but core analysis indicated that deconsolidation following acid stimulation could lead to borehole instability. The variable permeability, with higher values in the upper portion of the completion interval—in some zones exceeding 1 darcy—could make it difficult to adequately divert acid throughout the entire completion interval. The heavy crude oil of 17 to 21°API, with viscosity ranging from 50 to 90 cP [0.05 to 0.09 Pa.s], also raised concerns about compatibility with stimulation fluids. The well was perforated, and then, to ensure optimal fluid placement, was stimulated with VDA Viscoelastic Diverting Acid. The acidizing results were positive and the well exhibited good diversion and cleanup after treatment.

Following acid treatment, the well was tested using Schlumberger heavy-oil DST best practices. This included real-time monitoring and PhaseTester portable multiphase periodic well testing equipment (previous page, bottom). The compact PhaseTester system combines a venturi mass-flow measurement with measurements of dual-energy gamma ray attenuation and fluid pressure and temperature to calculate gas, oil and water fractions. PhaseTester oil flow-rate results have proved to be more accurate and more stable than flow-rate measurements made by traditional phase separators (red). Flow rates are in barrels per day at stock-tank conditions.

Interpretation of pressure-transient data using production rates from the separator. The well-test history plot (top) shows discrepancies between observed pressures (green) and the modeled curve (red). In the log-log diagnostic plot (bottom) of the pressure and its derivative for the second buildup period (blue) and the third buildup period (red), the modeled curves for the pressure (solid curves) and the derivative (dashed curves) show large differences from the observed data.

pressure-transient data results in a good match between observed and modeled pressures and derivatives (left). The models underlying the two interpretations have permeabilities that differ by 16%. The permeability inferred from the PhaseTester data also agrees well with permeability from scaled-up core measurements.

Constructing and Completing Heavy-Oil Wells

Wells in heavy-oil reservoirs present a variety of well-construction and completion complexities. These include drilling stable boreholes in weak formations, accurately landing horizontal wells, designing tubular systems and durable cements for wells that undergo temperature extremes, and installing sand-control, completion and artificial lift equipment that must operate efficiently under the harshest conditions. All these operations benefit from an integrated engineering approach that can draw on global experience to provide solutions to new heavy-oil problems.

Wells that experience extreme variations in temperature, such as in CSS and SAGD projects, require specialized, high-performance completion equipment. High temperatures and temperature variation can cause common elastomers to fail. This results in broken seals, allowing pressure and fluids to escape up the casing, increasing the potential for casing corrosion and reducing effectiveness of steam injection.

Recently, Schlumberger engineers developed nonelastomeric systems capable of operating at cycled temperatures up to 650°F [343°C] and pressures up to 21 MPa [3,046 psi]. These systems maintain pressure integrity while allowing deployment of reservoir monitoring and control equipment (left).

Schlumberger high-temperature thermal liner hangers have been used in the Cold Lake field, where a major operator in Canada has been piloting a horizontal-well CSS program. With customized liners and pressure-tight seals at the top of the liner, the operator has been able to achieve good steam conformance—steam intake spread evenly over the length of the horizontal well—verified by time-lapse seismic surveys over the pilot area.

SAGD wells also need downhole equipment with high temperature ratings. These wells require high build rates, proximity control between injector and producer, flexible cement, sand control, and liner hangers, packers and artificial lift equipment capable of operating at temperatures that may exceed 280°C [536°F].
Steam generation is approximately 75% of the operating expense of a SAGD well. Reducing the steam/oil ratio (SOR) while maintaining production rate is key to improving operation profitability (right). Reducing steam input saves energy costs, decreases produced-water volume and treatment expenses and cuts down on CO₂ emissions.

An important component in the effort to reduce SOR is the REDA Hotline 550 high-temperature electrical submersible pump system, rated to run continuously at up to 550°F [288°C] internal motor temperature, or 420°F [216°C] bottomhole temperature. Its high-temperature thermoplastic motor-winding insulation was initially developed and patented for geothermal and steamflood wells. The complete system is designed to compensate for variable expansion and contraction rates of the different materials used in the pump design.

Use of an ESP allows the reservoir to be produced at a pressure that is independent of wellhead pressure or separator pressure, increasing the quality of steam that can be injected. This can decrease the SOR by 10 to 25%, saving about US$ 1.00 per barrel of oil produced. In addition, the Hotline 550 ESP has excellent reliability statistics; the longest running installation has been operating for 844 days. The Hotline 550 ESP is used by a number of Canadian operators, including Encana, Suncor, ConocoPhillips, Nexen, Total, Husky and Blackrock.

Monitoring Heavy-Oil Recovery

Understanding fluid flow in heavy-oil reservoirs is important for optimizing recovery methods, especially when heat is required to reduce viscosity and mobilize fluids. Several techniques have been developed, including distributed temperature sensing (DTS) systems, permanent pressure gauges, crosswell seismic and electromagnetic surveys, microseismic techniques and time-lapse seismic monitoring.

In 2004, Total E&P Canada installed an optical-fiber DTS system along a pilot SAGD production well to monitor temperature during production startup in the Joslyn field in Alberta, Canada. The reservoir produces from the McMurray formation, which is mined for bitumen in the eastern part of the lease. In the western part, bitumen in the 50-m interval is heated by injection of steam and pumped to surface.

Correlating temperature change with viscosity and flow rate, especially when the injector-producer region is first warming up, helps reservoir engineers modify steam injection to ensure that enough heat reaches the entire intrawell region. In addition to the fiber-optic temperature-sensing system in the producing well, the pilot project included three observation wells that penetrated the injector-producer region within 1 to 2 m [3 to 7 ft] of the SAGD wells (above). Observation-well temperature measurements were recorded by thermocouples over a 45-m [148-ft] interval.
To initiate the SAGD process, steam was injected into both wells for several months to reduce bitumen viscosity. In September 2004, a pump and DTS instrumentation string were placed in the producer, and production began while steam injection continued in the injector with a bias toward the toe. DTS data acquired from October through December show a general warming of the injector-producer region, but one zone near the heel of the well did not follow the trend (right).

In January 2005, the pump was replaced with an ESP. During the workover, steam injection halted and the DTS string was temporarily removed. A liner was also installed, and the DTS string was reinserted. Then steam injection resumed, concentrating on the heel of the injector. The new DTS data reveal rewarming of the injector-producer region (below right).

Closer inspection of the DTS data acquired after the workover shows an unexpected oscillation of up to 20°C [36°F] (next page, top). In comparison, DTS data prior to the workover show little such fluctuation. It is believed that the temperature oscillation in the postworkover data is caused by spiraling of the coiled tubing string that contains the DTS instrumentation. Before workover, the DTS string was probably lying along the bottom of the slotted liner. However, during workover, the string was reinserted, and buckled inside the slotted liner.

The observed temperature oscillation corresponds to temperature values seen at the top and bottom of the producing well. The heated bitumen is up to 20°C hotter along the top of the horizontal producer than at the bottom. The observation-well temperature data acquired in Well OB1C before and after the workover also indicate that a significant temperature gradient can exist across the cross section of the producing well (next page, bottom). Interpreting temperature data therefore requires knowledge of the position of the temperature sensors in the wellbore. The continuous set of measurements provided by DTS instrumentation helped clarify the well’s performance.

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Moving Ahead in Heavy Oil

With heavy-oil reserves so abundant, companies that currently concentrate on production of conventional oils are entering the heavy-oil arena, joining companies that have produced heavy oil for decades. These newcomers may bring new technologies, helping to fill technology gaps that have been identified by long-time producers and other organizations. For example, the Alberta Chamber of Resources has compiled a list of advances necessary to allow production from oil sands to reach 5 million bbl/d [800,000 m³/d], or 16% of North American demand by 2030. Achieving this vision will require investment in technology improvements for mining, in-situ recovery methods and upgrading.

For every advance made toward enhancing heavy-oil recovery methods, numerous new avenues point to directions needing more work. In the area of fluid characterization, scientists are trying to extract more information about oil chemistry and component structure from logging and laboratory measurements. For example, progress is being made in linking NMR diffusion distributions with molecular chain lengths of crude oils. Researchers are working to add fluorescence measurements to current downhole fluid-analysis practices based on spectrometry, allowing more accurate fluid characterization and acquisition of continuous downhole fluid logs. Efforts are being made to standardize laboratory techniques, such as SARA analysis, so that results from different laboratories may be compared. Advances in understanding crude-oil's heaviest components—asphaltenes—have the potential to not only improve heavy-oil recovery, but also help solve flow-assurance problems in lighter oils.

Heavy-oil experts agree that there is no universal solution for evaluation and recovery of heavy oil. Some improvements, such as in log interpretation, may need to be customized for a particular region. In other cases—for example, the development of new materials that raise the operating temperatures of downhole completion equipment—successes may have widespread application. Still other developments, including advances in real-time monitoring, may come from the combination of methods already proven effective separately.

Another point of agreement is the need to continue to factor environmental concerns into the development of heavy-oil resources. In bitumen mining and current in-situ recovery projects, environmental and cultural considerations form important parts of the business model, including reclamation of mined areas, mineral recovery to make use of waste materials, minimization of water usage, issues related to indigenous peoples and reduction of greenhouse-gas emissions. New projects will have to be sensitive to these and other factors, including CO₂ emissions, preservation of permafrost and other fragile ecosystems and reduction of the energy expended to heat heavy oil.

If heavy-oil reservoirs have one advantage over their lighter counterparts, it is their longevity. Heavy-oil fields can produce for 100 years or more, as do the ones discovered in California in the late 1800s. By some estimates, the oil sands in Canada can produce for several hundred years. Investments made now will pay off long into the future.

—LS
Most data have little intrinsic value. The value arises from using data and information to achieve an end, whether that is optimizing production, tracking a business enterprise or managing a country's resources for the benefit of its citizens. Increased pressure to maximize output from existing fields and find new reserves drives the need for automated and efficiently managed E&P data systems.

Resource holders in control of these assets may be local or national, or may be members of regional cooperatives. Easily accessible and transparent data centers give these governmental bodies a competitive edge in attracting a full spectrum of investor companies. Increased transparency assures fairness in all transactions. A resource center that operates more efficiently and with more openness is appealing to investors and serves as a catalyst for business growth.

In an active data center, key business activities between government, industry and research institutions are conducted to encourage business growth. As a further advance, traditional data centers that were limited to E&P data are now expanding to include other resource information such as geotechnical, water, mining, cultural, agricultural, industrial and transport data.

Data management in the E&P sector has continually evolved over recent decades, driven by advances in information technology and the application of best practices. However, the same technology has also fostered an exponential growth in the types and complexity of data. Cost-effective computing technology has enabled new or more advanced data processes and techniques such as prestack depth migration, prestack seismic interpretation and analysis, and time-lapse, or four-dimensional (4D), seismic processes. There are also seismic-acquisition techniques such as the Q-Marine or Q-Land single-sensor systems that allow prestack data to be reformed to create multiple data volumes with specific attributes to meet current and future needs of geoscientists.

Real-time drilling operations, continual monitoring of production, temperature and pressure, as well as an increase in the number of captured images, have also contributed to the increase in data volume. The diversity of data and their interrelationships add other dimensions of complexity. Other significant sources of data include remote sensing, paleontology, geochemistry, cores and thin sections, and supervisory control and data acquisition (SCADA) systems. This is by no means an exhaustive list of data sources.

In the downstream arena, refineries can generate more than one terabyte of data each day. While much of this information is transitory and of limited value, increasing levels of captured data result from greater regulatory control and pressure to optimize the use of these key facilities.
This article describes how resource holders use data to manage the energy industry and the evolution of data management from a national data repository (NDR)—a static, closed system in which the data are gathered and archived—to a dynamic, open national data center (NDC). Examples show NDCs with traditional E&P data and those that also include other resources such as information on rivers, forests, fisheries and economic data. Also presented are different business models of NDCs.

**Historical Perspective**

Companies have acquired resource data for several decades, with a value that often exceeds billions of dollars. Without effective data-management processes, 5% to 10% of stored or captured data may be lost every year. To make the situation worse, technology continually evolves, making storage systems obsolete. For example, old tapes become unreadable by present technologies, and the media may degrade with time. Much of the information is unique, representing a snapshot in time that cannot be reacquired if it is lost or degraded.

In the 1990s, governments and national oil companies realized the value of establishing processes for managing and preserving all data generated from E&P activities. About 80% of most companies’ knowledge is in unstructured data such as spreadsheets, text files, documents on paper and other physical media. This wide variety in unstructured data is difficult to manage. When partners are involved, the situation becomes even more complex. For example, in Norway, prior to establishment of an NDC system called DISKOS, multiple copies of the same data were produced about 20 times in partner companies, leading to additional costs and inefficiencies.¹

Most NDRs emerged independently in different parts of the world in response to the need for efficiency and cost control, and to protect and preserve national assets. The specific focus of these operations was on internal data preservation rather than outward-facing activities, such as licensing-round support. Data entitlement, ownership and control were handled by people and processes, with the simplest of technology: pen and paper. Many of these paper-based centers now have adopted simple technology-based asset-management systems to make them more efficient.

The NDR concept progressed from this primitive model to represent a central repository of knowledge for the geotechnical community at large, including oil companies, governments and universities; it also served as a central resource for: 

for marketing speculative data. To support such a change, systems and processes that were used to manage assets evolved to support online access to these repositories. The Enterprise Finder database integration software came into usage, and more sophisticated map-based user interfaces were developed. As these sites were more outwardly focused, security and entitlement began to be handled through technology instead of manual processes.

In today’s climate of increasing oil and gas demand and with the availability of cost-effective technology, an increasing number of countries will be transforming their current inward-facing repositories to NDCs—outward-facing facilities.

Maximizing Value from Data and Information
There is a significant difference between an NDR and an NDC—between a passive repository and a dynamic center. Typically, the technology and processes of an NDR are designed to gather, organize, quality-control and store data and are generally devoid of advanced technologies for internal or external exploitation of the data. In contrast, an NDC is an activity center. Not only are resource data gathered, organized, quality-controlled and stored, but an expanded set of services is provided to help stimulate external investment in the country’s natural resources.

These services in an NDC enable multiple organizations and different software applications to directly access and transfer data, allowing visualization, economic analysis, forecasting and personnel training. The increased efficiency, accessibility and usage allow a government entity to create and extract more value from the data. These activities occur between government and industry, between partners, and between government and research organizations. An NDC allows the government to streamline monitoring of operator activities.

Certain new technologies can be applied to older data to extract further value, which is possible using a three-tier NDC architecture. This NDC architecture comprises desktop tools in the top tier, the Schlumberger integration engine (SIE) as the middleware, and in the bottom tier, multiple data repositories including the Seabed advanced E&P datastore system.

The Seabed relational data model is a new approach that incorporates advanced off-the-shelf database technology from Oracle, Microsoft, Java and ESRI. The Seabed data model has been published to advance industry-wide integration. It incorporates the best features of the Petrotechnical Open Software Corporation (POSC) and the Public Petroleum Data Model.
Summer 2006

(PPDM) to provide the flexibility and efficiency needed for the varied business demands and workflow practices of the upstream oil and gas industry. The Seabed data model covers the full spectrum of E&P domains, enabling data centers to customize solutions. In addition to storage and archival of exploration data, governments can monitor operational activities. The Seabed system is modular by domain, by functionality and by level of detail, providing full configurability that is vital for fit-for-purpose data centers. For example, a data center can start small with minimal functionalities and yet have the capability to expand progressively over time.

Incorporating concepts not previously used in data management, the Seabed data model extends the functionality of the relational database model, providing improved workflows and more efficient database maintenance and administration. It assures data quality with business rules, integrity constraints and standard reference values for data.

As part of this new architecture, the ProSource multidata source management application was developed to provide users with a single interface for browsing and integrating data that come from multiple repositories. This application allows users to visualize key data types—chart, wellbore, table, form, tree and spatially oriented data in a geographic information system (GIS) format—in customized workflows. Additionally, the ProSource tool leverages the capabilities of the Seabed datastore system and the SIE, making an information-management process more effective.

Entitlement is a key data-access requirement that enables an NDC to interact with external entities. Entitlement allows a government, company, data owner or other defined entity to grant or restrict access to its information based on a defined set of rules. These rules can be set to entitle data objects at any level of a data structure, down to the archive object, seismic polygon or line segment, geographical area, well, well log, log curve or data record. The Schlumberger system also supports hierarchies of entitlements for objects. Entitlement becomes much more important in repositories where many users are accessing public and private data through the same interface.

An example of geographic entitlement would be the granting of a license to a company for only a portion of a seismic survey that is contained within a particular exploration-lease boundary. The entitlement granted could then be further restricted to only certain data items associated with that seismic survey. For example, a user could be given access to a 3D post-stack time-migration data volume, but excluded from seeing or accessing a specific 3D depth migration. Entitlement can be further extended to restrict the functions that can be applied to a particular data item or items, such as read-only and export. Security enhances entitlement to further qualify a user or entity to grant access based on accepted security practices.

A new trend in the entitlement process is self-service management for entitlement. This process puts the entitlement capability in the hands of the entity submitting the data to the data center rather than having a back-office organization handle it manually. This process saves time and also reduces the potential for errors in the entitlement workflow. Under this scenario, company data administrators can automatically grant entitlements to partners, consultants or any other authorized data user. This methodology also helps to support potential trade, farmout or divestiture activities by providing an easy mechanism to grant access to data.

The entitlement process is implemented in the SIE. The SIE has a robust entitlement engine that can entitle items in many data centers, independent of data source. This process manages and enforces protection of entitlements independent of the application or repository from which the user is accessing information. The entitlement metadata are contained within the Seabed data model to allow auditing and reporting functions for this critical process.8

With secure access, active data centers provide a channel to research institutions with the goal of applying new data analysis, processing and interpretation techniques (above).

5. The Schlumberger integration engine allows access to various data repositories regardless of the data models, and provides the capability to view a common business object that has information in a number of separate repositories.
8. Metadata are data that describe other data, for example source, creation date, keywords and format information.
Cutting-edge research could lead to ideas for enhanced hydrocarbon recovery and identification of new reserves. These advances could then stimulate new investment in the development of the resource base.

While the goal of many governments is to attract investors or partners to develop their resources, increased competitiveness in the global economy requires openness and transparency to attract key investors. Establishment of an NDC can help achieve this end. Efficient access to data and advanced processes make assets more attractive to interested parties. The state can give these interested parties permission, or entitle them, to access certain levels of data. The NDC then makes assets work for the benefit of the state by enabling broader access to entitled stakeholders and clients to attract investment. This process avoids the redundancy of building and maintaining separate databases and duplicating data, which helps control the cost of managing the information.

An NDC fosters an understanding of natural resources and resource optimization, and therefore helps a country manage its natural resources efficiently and optimally. Adherence to standards and efficiency in regulatory reporting are mandatory. Submissions are checked and validated in a short time frame, and direct delivery of data between the field and the NDC is possible.

An NDC offers many benefits to oil and gas companies and service contractors. Not only can the approval process for seismic, logging and drilling programs be quicker, but the data can be cross-checked and validated when multiple interpretations and multiple sources or versions of data exist. Operators can access complete datasets, with data stored in a format that allows quick, easy loading to a project on a workstation. Finally, an infrastructure shared with partners means less hardware, software and office space, leading to operator cost savings.

Because of the many advantages of NDCs, many data repositories are gradually evolving to national data centers. This trend is clearly seen in an example from Colombia.

**Evolution from NDR to NDC in Colombia**

The existence of petroleum in Colombia can be traced back to the 16th century Spanish conquest of the village of La Tora, today known as Barrancabermeja. At that time, naturally seeping oil was used by the indigenous people as a relaxing medicine, among various other uses. The conquerors used this magic substance to waterproof ships. Centuries later, this strange black substance would become a prime energy resource and underpin Colombia’s entire economy.

There is some evidence that the first exploration well in Colombia was drilled in 1883 with a production capacity of 50 barrels per day \([7.9 \text{ m}^3/\text{d}]\.\) Today, the oil and natural gas of Colombia comprise more than 37 billion bbl \([5 \text{ billion m}^3]\) of oil equivalent, distributed in 18 sedimentary basins that cover an area of 1,036,400 km\(^2\) \([400,170 \text{ mi}^2]\).

The oil industry fuels the economy of the country, with 55.4% of export revenues coming from petroleum. In 1999, discovery of new reserves became a national priority to maintain self-sufficiency and revenue growth. This resulted in a series of reforms in oil policies—contractual and fiscal—to reactivate exploration. More than 60 concessions were signed. New technologies have been deployed to reduce the oil decline rate from 12% in 2001 to about 1% in 2005. However, internal consumption is still expected to surpass production between 2007 and 2008. Colombia will have to start importing oil to meet internal oil demand. This new reality required the adoption of new policies to facilitate and promote E&P activity.

Ecopetrol, the Colombian National Oil Company, devised plans for managing E&P data in the late 1990s that became a corporate strategy in 1998. In 2000, Ecopetrol launched the Colombian National Data Repository (Banco de Informacion Petrolera, or BIP), an organization that emerged as the official data repository for the oil industry in Colombia. In 2003, as part of a state reorganization, the BIP NDR became the EPIS (Exploration and Production Information Services) NDC, a project of the National Hydrocarbon Agency (ANH), and the new national organization for managing the country’s hydrocarbon policies (next page).

The main objectives of this new organization are to increase hydrocarbon reserves by promoting investment in new exploration projects through transparency and competitiveness, and to increase investor confidence in E&P projects by offering accurate, high-quality information that reduces exploration risk. Some of the challenges are improving delivery time, providing comprehensive, high-quality information, and managing large data volumes as new technologies are introduced.

### Implementing EPIS

To facilitate the transition from NDR to NDC, the ANH evaluated several factors needed for an efficient NDC. These include hardware and software technologies that speed up transactions and guarantee information security, and that enable data integration from different databases. Also key is the implementation of processes and procedures that allow replicability of standards, monitoring and traceability. Management and training of personnel are also important.

The five main functions of EPIS services are physical data reception and verification; technical data verification, data cataloging, loading and integration; technical data delivery; integrated browsing; and online help and physical-media technology service.

Physical data reception and verification involve validating data from oil companies, service companies and other parties against the official data-delivery manual—confirming quantities, formats, time frame and delivery location. Technical data verification enables data to be reviewed by a group of professionals in each area to ensure that the data comply with oil industry standards. Once this process is complete, the data are cataloged, verified and loaded into databases that are accessible to users. Integration is a key activity in this step for retaining data integrity among all technical databases.

Technical data-delivery service consists of searching, selecting and delivering—in digital or analog media—the stored technical data related to seismic acquisition, wells, maps or documents to ANH or any other company or person duly authorized by ANH.

A user can locate, select, visualize and then extract the relevant data that are stored in different physical repositories through an integrated Web portal called “My EPIS.” My EPIS has a text-oriented search interface, in English and Spanish; data can also be located quickly and easily through a graphical interface that uses location maps.

The many varied physical assets (more than 1,450,000), covering 50 years of petroleum history, are cataloged and bar-coded into 10 categories. These include data in a wide range of media and formats such as paper, tapes, CDs, videos, analog seismic, geologic or geophysical reports, maps, seismic sections, well logs, satellite images and film. More than 30 terabytes of data are stored in the EPIS repositories. Call-center and help-desk services ensure user support in any aspect of E&P technical data.

10. EPIS was awarded ISO 9000 Quality Certification in December 2004, making it the world’s first national data center with certified processes and procedures.

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Improved Web portal for Colombia data. The first EPIS Web portal in 2003 was a line-item interface (top). The current portal has a graphical interface (bottom) available in both English and Spanish with quick links to many features in a menu bar. Examples include (from left) the home page, sets of seismic data, data from individual seismic lines and current production statistics.

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browsing, downloading and administrative requests. An important service provided to investors is a “Data Room” that allows an authorized user or possible investor to visualize data to make informed decisions.

EPIS benefits for ANH are both tangible and intangible. Both the number of signed contracts and the revenues associated with the data-delivery packages have increased since EPIS replaced BIP (right). Other, more indirect benefits are less easily measured, but unmistakable. Making decisions at the right moment, with the right information, has a tremendous impact on project success, efficient use of resources and effective budget planning.

Currently, EPIS is an NDC that includes only E&P data. In the future, EPIS will include production data with associated services and technical support. The method of financial support will migrate slowly into a self-funded program, with the latest technological facilities that allow all users around the world to download their entitled data in real time. Another possibility for the future is inclusion of other types of resource information.

Advances in data-handling procedures and certain enabling technologies have allowed NDCs to progress to include downstream data such as petrochemical and other non-E&P resources such as rivers, forests and fisheries, in addition to transportation, and social and economic data types. A few countries have used this system to manage their mining industries—diamonds, gold and metals—while others are using it to manage other resources like subsurface water (next page). An example of a more wide-ranging NDC is that of the Yamalo-Nenetsky Autonomous District of the Russian Federation (Yamal) in western Siberia.

**Yamal: Extending the NDC Domain**

Yamal is one of the largest regions of the Russian Federation with more than 50% of its territory in the polar region. The Yamal region produces about 90% of Russia’s gas and about 15% of its oil and represents 22.5% of the world’s gas production. There are more than 53 operating companies working in Yamal, and 157 licences have been issued for 42 exploration and 115 field-development projects.

Since the beginning of exploration about 40 years ago, enormous volumes of E&P data have been generated from 600,000 km [372,833 mi] of seismic coverage, and data from 6,500 exploration wells and 20,000 development wells. With major political and economic changes sweeping across Russia in the 1990s, the three state E&P enterprises in the region were reorganized into more than 30 independent companies, and the region’s hydrocarbon resource information was distributed among them. About 60% to 80% of user time was spent searching for, validating and reformatting data. Media deterioration, poor storage facilities and other factors contributed to an estimated annual data loss of 5% to 10%.

In 1997, to preserve the information resources of the region and introduce modern data-management standards, the Yamal administration decided to create a single, state-of-the-art repository of old and newly obtained E&P data. Schlumberger received a contract to provide advanced technology and information-management expertise for the Yamal Territorial Data Bank (TDB) project, and the operations of TDB were managed by the Siberian Scientific Analytical Centre (SibSAC) in Tyumen, Russia. The Schlumberger-SibSAC partnership provided the best available combination of technology, experience and regional expertise.

The first phase began in 1998, with loading of geological, geophysical and production data to the TDB. Most exploration activities included seismic surveys and wells that were originally fulfilled used government financing; therefore the government owned the information. Most data were on paper; they were scanned into the TDB or digitized. About 1 million scanned images were loaded for about 5,200 exploration wells. The production wells included well-construction and production data.

Some NDRs and NDCs around the world. Data repositories and national data centers around the world are owned by national oil companies (circles) or national, regional or local governments (triangles). The operation and the technology used are indicated in different colors: government (brown), Schlumberger (blue), Halliburton (red) and other (gray). There are multiple locations in USA at the state level.
The TDB in Salekhard, Russia, contains the central data repository and provides single point-of-entry secured access to the users (above). Data are fed to a preparation, quality-control and loading center located in Tyumen before they are replicated and sent to a central repository. There are also several mobile centers that serve as points of data gathering and preparation.

The first phase of data loading presented many challenges. More than 50% of the data collected existed in analog form. Other problems were several generations' change of hardware and techniques, physical deterioration of media and the loss of originals. Close cooperation with SibSAC, rapid implementation and focused effort along with use of a comprehensive suite of Schlumberger software technology allowed gathering and storing of 95% of available data, around 10 terabytes, in the TDB by the end of 2002. SibSAC was responsible for gathering, checking, transcribing and loading, while Schlumberger was responsible for technical solutions, training, documentation and process consulting.

The data included 854 seismic surveys equaling 450,000 km [279,625 mi] of seismic lines that were previously stored on 70,000 tapes; 720,000 documents for 6,000 wells; digital and paper logs from nearly 8,000 wells; and production information for approximately 20,000 production wells.

Overall, the Yamal NDC approach has been successful. The NDC operation is adequately funded and the membership provides cost savings by sharing the cost and benefits among several companies. Data sales provide about half the operational cost. Most importantly, the business model supports a long-term vision that fosters and supports continual improvements to and innovation within the data center.

Because of this success, the Yamal administration decided to extend data coverage beyond hydrocarbons to a natural-resources domain (next page). The second phase of data management includes information about land, rivers, water, fish, wildlife and forests. Inclusion of cultural data such as administrative divisions and population helped ensure maximum efficiency in using human resources in the regional labor market.

Yamal had limited information on land usage about 15 years ago. Monitoring of land usage was needed to assess land values, control the environment and pollution, and regulate operator activities. Also required were verification of land-use regulations, prevention of illegal activities and investigation of liabilities.

Yamal's TDB has the potential to apply this new information-management structure to the region's infrastructure management such as railways and roads, rivers and seaports, electrical and telephone lines, and pipelines. This
infrastructure and facilities database is being created within the framework of an integrated information system for the general economic development of the territory.

Work on the establishment of a social and economic parameter database was recently initiated for further enhancing the integrated information system. This would aid in preparing regional budgets, setting investment policies, facilitating economic forecasting, and evaluating the living standards of the population.

The regulatory and legal framework encompasses the integrated information system. It gives users access to the laws of the Russian Federation as well as to regional legal requirements—at a federal level and at a local level—that are specific to the particular region.

This TDB structure enables management to make informed decisions aimed at a stable long-term development of the region. Yamal may have set the stage for a future comprehensive information-management system encompassing the entire Russian Federation.

The change from managing only E&P data to managing other resources is less a technical problem than a political or organizational issue. At the Sixth International Meeting of the National Geoscience Data Repositories (NDR6) in The Netherlands, the participants noted that 80% of the difficulties of establishing an NDC relate to the following four items: legal issues, financing, government buy-in and industry buy-in.²³

However, funding an NDC remains one of the important challenges. The global expenditure on NDRs and NDCs is estimated to be in the range of US$ 60 to 90 million annually. The typical cost for sustaining a significant NDC ranges between US$ 2 to 5 million yearly, with the major cost related to the storage and management of seismic trace data.

Business Considerations

Petrotechnical data acquired in the process of finding, developing and producing oil and gas are complex, voluminous and unique to the industry. Data managers in this industry are highly skilled specialists, usually from geoscience and information-technology backgrounds. These professionals are challenged with mastering advanced technology, complex formats, and poor and inconsistent data quality. The data's origin must be geospatially located with a high degree of accuracy both horizontally and vertically. As a result, professional management of E&P data has a significant cost that is often overlooked by many organizations.

The original business justification for the first NDRs was quite simple: centralize the storage and management of petrotechnical data in a common location and then distribute the cost among several organizations that use or need the data. An NDR provides a greater value to the government if its capabilities are expanded to become a national data center. This is because an NDC is an effective cost saver and also a revenue generator, which benefits both the government and the users.

The business models for NDCs may vary. They may be government-sponsored, industry-sponsored, or sometimes even commercial ventures. Business models may be broadly characterized into four types: government outsourcing to a third party, an industry-led consortium, those funded by an agency, and agency-funded with cost recovery.

Government licensing or outsourcing—

The government-licensing or outsourcing business model allows one or more vendors to own and operate an NDC as a for-profit commercial venture. Industry users purchase data access, downloads and information products from the vendor based on market rates that compensate the vendor for its investments in infrastructure, software and staffing. For the sponsoring government entity, this option provides the core benefits of an NDC without major government investment.

Though this approach is attractive to government agencies from a cost perspective, it has not been successful in fully funding an effective NDC, and consequently has seen limited implementation. The barriers include

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warehousing storage cost for physical data, collection and management cost for private data, access costs for government and universities, an unrealized expectation that demand for data access will fully fund the operation, and expectation by many in government that public data are free.

One variant in this concept has had success. The notion in the USA and some other countries is that any public information managed by the government is available to any citizen who requests the information at the cost of distribution. As a result, there is an industry comprising numerous data vendors that purchase E&P data from various state and federal agencies and then provide some value-added processing.

The data-vendor model is particularly common in North America where there are huge numbers of E&P companies and millions of wells to manage. The data are sold to the industry on a commercial basis. The vendor databases in some regions fulfill the need to provide data access to the industry that would otherwise be achieved by an NDC. In this manner, a vendor database can be considered a form of pseudo-NDC that provides the data-distribution functions. However, this service is incomplete and falls short when compared to the benefits of a government NDC.

Industry-led consortium—In an industry-led consortium, several operators and participants in a given region form a group that will fund an NDC. Companies pay a fee to join the consortium. The government agency is included as a special member with minimal investment. A board governs the group with representation from all members. Two examples of the consortium model include Norway’s DISKOS and the UK’s Common Data Access (CDA).14

DISKOS is a group of 17 members, including Norway’s largest acreage holder, Statoil, and a government agency, the Norwegian Petroleum Directorate. The funding model considers both fixed and variable cost. The operation is funded by member fees, including a set fee plus a portion that is based on the volume of data that is managed for each member. Activity-based services, such as loading new datasets, are established as a variable cost and have an associated fee based on the volume of the data loaded. This approach allows the NDC to add resources to match peaks in demand.15

A third component of NDC funding is commercial charges for value-added services. Typically, an NDC allows vendors to provide services on a commercial basis. A range of activities that leverage the data center’s capacity for storage, professional data-management services and connectivity are available. Examples include corrections to data that do not meet the standards set by the government, management of a member’s data that originate from out-of-country, and management and delivery of Prestack seismic datasets for processing.

DISKOS has established best practices for apportioning member costs with a fixed-cost element for predictable cost and variable costs for activity-based services. Also, the outsourcing approach encourages efficiency in competitive bidding and service-level agreements. Members have saved significantly by pooling resources with a central service. DISKOS saves operators an estimated US$ 60 million annually. Typically, it takes about 4 to 5 years for tangible benefits to exceed the cost of operating the NDC (above).16

Agency-funded—In an agency-funded model, the government agency that is responsible for the energy industry funds the NDC. The agency is the custodian of the information assets and promotes and manages oil and gas resources. Typically, these governments view the receipt and management of petrotechnical information from operators as the legal responsibility of the state and therefore budget for the NDC program. The business premise is that government should play an active role in the health and vibrancy of the industry it stewards by providing quality data to the industry. The NDC serves as a means of

14. CDA is a nonprofit subsidiary of United Kingdom Offshore Operators Association that was set up in 1994 to provide data-management services to members and to the oil industry in the UK. CDA facilitates effective collaboration between oil companies, service companies and regulatory authorities in the UK. For more on CDA: http://www.cdai.com/HOME/page33866.asp (accessed April 20, 2006).
15. The consortium business model has been a success for DISKOS for the past 12 years. DISKOS is self-funded and all members actively use the service. About 60 terabytes of data have been loaded into the DISKOS system, including 500 2D seismic surveys, 1,500 2D seismic surveys and 18,000 well logs. Benefits include efficient access to high-quality data that results in faster project cycle time and risk mitigation. Government-to-business (G2B) processes for data submissions have been streamlined with improved quality and service.
17. The OCS Connect project is a phased, multiyear, electronic government (e-government) transformation of the Offshore Minerals Management (OMM), a division of the United States Department of Interior Minerals Management Service (MMS). The project aims to improve core operational processes of the OMM program, which includes replacement of legacy information-management tools with state-of-the-art commercial products. These will help to meet the needs of the stakeholder and user communities such as federal, state and local government, private industry, the scientific community, international agencies and the general public. OMM will employ the Seabed advanced E&P datastore system as part of the OCS Connect project.
Attracting external investment and new players. This type of NDC is typically owned and operated by the state.

Other examples of agencies using an agency-funded model include the Minerals Management Service in the United States, and the Department of Industry and Resources in Western Australia. An NDC can attract international funding in terms of grants or loans to the countries that have hydrocarbons but are not among the world leaders in production. For example, the World Bank approved a loan of US$ 15 million in 2005 to support the government of Gabon’s efforts towards improved management of biodiversity, environment and natural resources. This later led to an NDC established by the Gabon government. In other examples, the World Bank funding was initially used to initiate NDCs in Bolivia and Cameroon.

Agency-funded with cost recovery—In this business model, a government funds an NDC project and ongoing operations and then allocates the costs to the operators within its jurisdiction. Unlike the industry-led consortium, NDC governance is dictated by the agency with input from industry members. The funding has the same components described in the industry-led consortium model. This model generally includes a one-time member fee, an annual fee based on company size, and usage fees tied to variable costs.

The Yamal TDB is an example of an agency-funded model with cost recovery. Regional administration manages the operation of the NDC with a focus on data delivery to end users, with SibSAC managing the data and Schlumberger providing information-management technology and systems-integration services. The regional administration fully funds the NDC, although it recovers the costs by selling data access, downloads and information products to all E&P companies in the province. The Yamal NDC began operation in 1998, and adopted a self-funding model in 2000.

In the future, hybrid business models are possible where the government agencies for energy, driven by e-government initiatives— electronic transactions—provide fundamental communication and information capabilities that are open to the public. This will spawn a new industry of value-added services that go far beyond today’s data distribution. The key is the E&P industry embracing e-government transformation and staying dedicated to a vision of openness.

**Conditions for a Successful NDC**

Criteria for a successful NDC are based upon transparency, degree of self-support, having an industry or a government focus, cost savings, value creation and fairness to all parties.

An important consideration is how well the business model facilitates transparent financial transactions. Openness brings transparency and ultimately reduces business corruption that is possible in the traditional manual process. This serves as a catalyst to attract more investors.

The ability of a business model to self-fund the NDC implementation, operations and long-term evolution is essential. The needs of industry and the needs of the government typically oppose each other. There is a healthy tension between these groups that naturally seeks a balance in a well-managed industry.

NDCs are expected to save costs by centralizing information management. These savings are realized only if the NDC delivers information well enough that the shared products and services are not replicated in the member companies themselves. This indicator reflects the likelihood of the business model to encourage actual savings.

Finally, business models should be fair to all players in the marketplace, including E&P companies, universities and service companies from small to large, regardless of the length of time in the specific country.

There is no correct or optimal business model. Each geopolitical entity adopts a business model that is appropriate for its social and economic conditions. Each type of business model can be augmented with contractual terms and conditions, governance approaches and legislation to achieve the key performance aspects of the NDC.

**What’s Next—A Proliferation of NDCs?**

Governments around the world are in the process of implementing seamless transactions between government and business, between government and people, and within various government agencies. While market drivers continue to push the trend toward more open access, technology—more importantly cost-effective technology—continues to exert pressure on speeding up legislation to encourage external investment.

NDCs of the future will incorporate a wide variety of data types in addition to E&P, geoscience, mining and groundwater. According to an economic study done by The Netherlands Institute of Applied Geoscience, an annual investment of EUR 15 million in managing oil and gas, industrial materials and groundwater resources results in an estimated value of approximately EUR 10,000 million per year.

As the value of these NDCs continues to become better known, the rapid growth in their implementation will continue (left). Integration will be driven to the next level, where NDCs become activity hubs in a large global network. This broader network will increase the availability of investment and will encourage more countries to improve and transform their NDRs from a passive position of merely preserving and storing data, as done in the past, to a dynamic one of generating new investments. —RG/MAA
Contributors

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An asterisk (*) is used to denote a mark of Schlumberger.
Gas Shales. The most abundant of sedimentary rocks, shale is characterized by its extremely low permeability, and is usually considered a seal, rather than a reservoir. However, given the right combination of geology, economics, infrastructure and technology, organic-rich shales can be developed into successful gas plays. The success of the Barnett Shale gas play in north-central Texas is prompting operators to search for other basins of similar potential. This article reviews the technology required to exploit and generate hydrocarbons and the conditions necessary for shale to produce those reservoirs.

Subsidence and Compaction. Subsidence above reservoirs may have enormous economic consequences, which may not be limited to superficial damage to oilfield infrastructure. Compaction results from depleting formations that are mechanically weak; it is the cause of industry-related subsidence. The article describes the fundamentals of compaction and subsidence, and includes case studies from several active fields.

Energy Processes.

Fundamentals of Renewable Energy Processes
Aldo Vieira da Rosa
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The book deals with the fundamental mechanisms and processes of energy management. Among the topics covered are heat engines, hydrogen energy, solar energy, fuel cells, and energy from wind and water. Each section includes a series of problems.

Contents:
• Generalities
• A Minimum of Thermodynamics and of Kinetic Theory of Gases
• Mechanical Heat Engines
• Ocean Thermal Energy Converters
• Thermoelectricity
• Thermionics
• AMTEC
• Radio-Noise Generators
• Fuel Cells
• Hydrogen Production
• Hydrogen Storage
• Solar Radiation
• Biomass
• Photovoltaic Converters
• Wind Energy
• Ocean Engines
• Index

[The book] is an excellent treatment of the technical background of renewable sources of energy. Da Rosa...is an authority in this area and has the gift of precisely defining each segment of each topic. The tone is reader-friendly....

The material is very much up-to-date.... Highly recommended.

Bursting the Limits of Time: The Reconstruction of Geohistory in the Age of Revolution
Martin J.S. Rudwick
University of Chicago Press
5801 Ellis Avenue
Chicago, Illinois 60637 USA
2005. 708 pages. $45.00
ISBN 0-226-73111-1

Written by a respected science historian, the book provides detailed, scholarly coverage of the beginnings of modern geology from the mid-1780s to the mid-1820s.

Contents:
• Naturalists, Philosophers and Others
• Sciences of the Earth
• The Theory of the Earth
• Transposing History into the Earth
• Problems with Fossils
• A New Science of “Geology”?• Denizens of a Former World
• Geognosy Enriched into Geohistory
• The Gateway to the Deep Past
• Earth’s Last Revolution
• Sources, Index

...quite simply a masterpiece of science history....Rudwick’s text is beautifully written and grips the attention throughout.

All ten chapters are beautifully illustrated, with 179 contemporary black-and-white prints interwoven with the text. There are copious footnotes on every second page, as well as complete sources and references.

The book should be obligatory for every geology and history-of-science library, and is a highly recommended companion for every civilized geologist who can carry an extra 2.4 kg in his rucksack.

...it tends to be rather repetitive, because the author describes every nuance of each idea.... But a much shorter text could have covered the same subject matter, even over a broader time range, and thus reached a wider audience.

A Crack in the Edge of the World: America and the Great California Earthquake of 1906
Simon Winchester
HarperCollins
10 East 53rd Street
New York, New York 10022 USA
2005. 480 pages. $27.95
ISBN 0-06-057199-3

Winchester, an Oxford-trained geologist, discusses how the 1906 San Francisco earthquake led to greater scientific study of the movements of the Earth. He explains plate tectonics theory and the creation of the San Andreas Fault, along with the geologic exploration of the American West in the late 19th century. The book also covers the social and political shifts caused by the disaster, such as the Pentecostalist movement and the increase in the local Chinese population.

Contents:
• Chronicle: A Year of Living Dangerously
• The Temporary City
• Chronicle: Such Almost Modern Times
• From Plate to Shining Plate
• Chronicle: The State of the Golden State
• How the West Was Made
• The Mischief Maker
• Chronicle: City of Mint and Smoke
• Overture: The Night Before Dark
• The Savage Interruption
• Ripples on the Surface of the Pond
• Perspective: Ice and Fire
• Appendix: On Taking an Earthquake’s Measure; With Gratitude; A Glossary of Possibly Unfamiliar Terms and Concepts; Suggestions for Further Reading, with Caveats; Index

Winchester’s stories can be like Gobstopppers: concentric rings of ideas, events, people’s lives—everything but the topic he purports to describe until hundreds of pages into the book, and by then the candy center may be slightly disappointing. [The book] began to feel a bit tedious after awhile.
... although the book might be boring and frustrating at times, the payoff of Winchester’s descriptions of the Great Earthquake is worth sticking it out.

Lubick N: Geotimes 50, no. 10 (October 2005): 53-54.

 Applied Stratigraphy
Eduardo A. M. Koutsoukos (ed) Springer Publishing
101 Philip Drive
Norwell, MA Massachusetts 02061 USA
2005. 488 pages. $149.00 ISBN 1-4020-2632-3

The book contains six chapters written by experts in their field and is organized into four parts: evolution of a concept, the search for patterns, the search for clues, and modeling the record.

Contents:
• Stratigraphy: Evolution of a Concept
• Buried Time: Chronostratigraphy as a Research Tool
• Ecstratigraphy’s Basis, Using Silurian and Devonian Examples, with Consideration of the Biogeographic Complication
• Devonian Palynostratigraphy in Western Gondwana
• Carboniferous and Permian Palynostratigraphy
• Biostratigraphy of the Non-Marine Triassic: Is a Global Correlation Based on Tetrapod Faunas Possible?
• The K-T Boundary
• Chemorobotics
• Paleobotany and Paleoclimatology
• Part I: Growth Rings in Fossil Woods and Paleoclimate
• Part II: Leaf Assemblages (Taphonomy, Paleoclimatology and Paleogeography)
• Palynostratigraphy and Its Stratigraphic Application
• Sequence Biostratigraphy with Examples from the Plio-Pleistocene and Quaternary
• Taphonomy—Overview of Main Concepts and Applications to Sequence Stratigraphic Analysis
• Significance of Ichnofossils to Applied Stratigraphy
• Cyclostratigraphy
• The Role and Value of “Bio-steering” in Hydrocarbon Reservoir Exploitation
• Quantitative Methods for Applied Microfossil Biostratigraphy
• References, Appendix, Index

The chapter on the K-T Boundary, by Eduardo Koutsoukos, is especially well written; most of the other chapters are above average, and there is a wonderfully extensive bibliography (74 pages). Highly recommended.


The Velocity of Honey and More Science of Everyday Life
Jay Ingram
Thunder’s Mouth Press
245 West 17th Street, 11th Floor
New York, New York 10011 USA
2005. 211 pages. $25.00 ISBN 1-56025-654-0

Among the topics probed by Ingram, host of the Discovery Channel’s Daily Planet and author of The Science of Everyday Life, are the physics of coin- spinning, stone-skipping and paper- crumpling; the math talents of animals and infants; the six degrees of separation myth; and the cognitive psychology behind a range of human capabilities, from catching a fly ball to working an ATM machine.

But the greatest attraction of The Velocity of Honey is Ingram’s intelligent but gentle, self-deprecating, personal

This well-written book does a great job of summarizing complex topics through simple calculations and examples, and provides the right balance of cultural background and scientific data.

Even if the hypothesis ultimately proves partially or fully incorrect, Ruddiman has done his job as a scientist by stimulating new research directions, and for questioning the role of humans in global climate change before the Industrial Revolution.

Lachnit MS: Geotimes 51, no. 3 (March 2006): 49-50.

...his thesis will please no one. Those alarmed by present trends will object to the notion that anthropogenic warming saved us from glacial advances and associated climate deterioration. And those who, when it comes to energy use, place comfort over concern or who want to protect special interests will resist the implication that climate is indeed quite sensitive to human additions of carbon dioxide and methane to the atmosphere.

The Cosmic Landscape: String Theory and the Illusion of Intelligent Design
Leonard Susskind
Little, Brown and Company
1271 Avenue of the Americas
New York, New York 10020 USA
2005. 416 pages. $24.95
ISBN 0-316-15579-9

Written by a founder of string theory, the book deals with basic concepts of modern particle physics. Much of the discussion centers on a controversial concept, the anthropic principle, a hypothetical principle that says the universe is so huge, diverse and rich with possibilities that the anthropic principle can make sense — without the necessity for intelligent design.

Contents:
• The World According to Feynman
• The Other of All Physics Problems
• The Lay of the Land
• The Myth of Uniqueness and Elegance
• Thunderbolt from Heaven
• On Frozen Fish and Boiled Fish
• A Rubber Band-Powered World
• Reincarnation
• On Our Own?
• The Branes Behind Rube Goldberg’s Greatest Machine
• A Bubble Bath Universe
• The Black Hole War
• Summing Up
• Epilogue
• A Word on the Distinction Between Landscape and Megaverse
• Glossary, Notes, Index

The book also tries to justify the multiverse idea in terms of the ‘many worlds’ interpretation of quantum theory — an unproven and totally profligate viewpoint that many find difficult to take seriously.

This book gives a great overview of this important terrain, as seen from an enthusiast’s viewpoint.


The Equations: Icons of Knowledge
Sander Bais
Harvard University Press
79 Garden Street
Cambridge, Massachusetts 02138 USA
2005. 96 pages. $18.95

Bais, a theoretical physicist at the University of Amsterdam, presents 17 of the basic sets of physics equations that represent turning points in humanity’s understanding of the world. After a brief introduction to basic mathematical concepts, he explains key equations in such fields as mechanics, thermodynamics, electromodynamics, hydrodynamics, relativity and quantum mechanics.

Contents:
• Introduction
• The Tautological Toolkit
• Rise and Fall: The Logistic Equation
• Mechanics and Gravity: Newton’s Dynamical Equations and Universal Law of Gravity
• The Electromagnetic Force: The Lorentz Force Law
• A Local Conservation Law: The Continuity Equation
• Electrodynamics: The Maxwell Equations
• Electromagnetic Waves: The Wave Equations
• Solitary Waves: The Korteweg-De Vries Equation
• Thermodynamics: The Three Laws of Thermodynamics
• Kinetic Theory: The Boltzmann Equation
• Hydrodynamics: The Navier-Stokes Equations
• Special Relativity: Relativistic Kinematics
• General Relativity: The Einstein Equations
• Quantum Mechanics: The Schrödinger Equation
• The Relativistic Electron: The Dirac Equation
• The Strong Force: Quantum Chromodynamics
• Electro-Weak Interactions: The Glashow-Weinberg-Salam Model
• String Theory: The Superstring Action
• Back to the Future: A Final Perspective

In a book of only 96 pages, it is a real challenge to do much more than indicate to the reader the enormous richness of these equations and the imaginative ways they can be used to extend our understanding of the workings of nature at all levels.

Who will gain most from reading this book? It has to be someone who wants an introduction to the power of mathematics in describing natural phenomena without actually having to do the maths.

... In addition to its pedagogical value, Bais’s book presents these icons of our physical world in all their beauty. It is very good to be reminded of this.


The Long Emergency: Surviving the Converging Catastrophes of the Twenty-First Century
James Howard Kunstler
Atlantic Monthly Press
841 Broadway
New York, New York 10003 USA
2005. 307 pages. $23.00 hardcover; $14.00 paperback
ISBN 0-87113-888-3

The author argues that cheap oil underlies all of our suburban, high-rise, mega-agriculture and car-based lifestyles, and that alternative energy sources cannot fill the energy gap. Kunstler describes what to expect after the era of affordable energy is over, preparing readers for catastrophic economic, political and social changes.

Contents:
• Sleepwalking into the Future
• Modernity and the Fossil Fuels Dilemma
• Geopolitics and the Global Oil Peak
• Beyond Oil: Why Alternative Fuels Won’t Rescue Us
• Nature Bites Back: Climate Change, Epidemic Disease, Water Scarcity, Habitat Destruction and the Dark Side of the Industrial Age
• Running on Fumes: The Hallucinated Economy
• Living in the Long Emergency

Overall, Kunstler’s tapestry of destruction assumes a race of much more limited flexibility and creativity than history shows humanity to be.


The indictment of suburbia and the car culture that the author presented in The Geography of Nowhere turns apocalyptic in this vigorous, if overwrought, jeremiad. Kunstler notes that global oil production has peaked and will soon dwindle, and argues in an eye-opening, although not entirely convincing, analysis that alternative energy sources cannot fill the gap, especially in transportation. The result will be a Dark Age in which “the center does not hold” and “all bets are off about civilization’s future.”... Kunstler’s critique of contemporary society is caustic and scintillating as usual, but his prognostications strain credibility.


Having made a powerful case that it is too late to avoid serious trauma, Kunstler speculates on what life will be like during the painful transition period, as cheap petroleum wanes. The question is well worth asking, if only to stimulate creative thinking about alternatives to a high-energy lifestyle.
